BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plan Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	Application A.15-07-002 Application A.15-07-003 Application A.15-07-006

(Not Consolidated)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resources Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005 (Filed July 1, 2015)
And Related Matters.	Application A.15-07-007 Application A.15-07-008

COMMENTS OF THE OFFICE OF RATEPAYER ADVOCATES ON THE ALJ RULING INVITING COMMENTS ON INTEGRATION CAPACITY ANALYSIS (ICA) METHODOLOGIES, ICA WORKSHOP REPORT, LOCATIONAL NET BENEFITS ANALYSIS (LNBA) WORKSHOP AND DEMONSTRATION PROJECTS A AND B.

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I. INTRODUCTION

Pursuant to the Administrative Law Judge (ALJ) ruling (Ruling), dated February 18, 2016,[1] the Office of Ratepayer Advocates (ORA) submits these timely filed comments. ORA files these comments pursuant to its statutory mission to obtain the lowest possible utility rates consistent with reliable and safe service levels. The Ruling requests feedback on the Integration Capacity Analysis (ICA) methodologies, the ICA Workshop Report,[2] the Locational Net Benefits Analysis (LNBA)[3] and Demonstrations Projects A and B. In consideration of the California Public Utilities Commission (Commission) adoption of the ICA and LNBA methodologies and provisional authorization of Demonstration Projects A and B, ORA recommends the Commission take the following steps:

<u>ICA</u>

- provisionally adopt the ICA methodologies with the recognition that increased transparency and uniformity between the IOUs' methods is required prior to final approval, and requiring Investor Owned Utilities (IOUs) to submit detailed ICA methodologies to the Commission and stakeholders as a supplemental filing prior to commencing Demonstration Project A.
- approve Demonstration Project A on condition that reference circuits and reference use cases be developed for comparative analyses of Demonstration Project A results.

<u>LNBA</u>

- adopt ORA's alternative approach for an expanded LNBA tool, which assesses distributed energy resources (DER) by function, then allows calculation of DER value across a selected area consistent with integrated distributed energy resources (IDER) proceeding cost-effectiveness calculator.

II. DISCUSSION

A. <u>The ICA and Demonstration Project A</u>

The ICA is intended to provide a uniform, technology-neutral methodology to calculate the capacity of an IOU's electric distribution system at the feeder level. The ICA is intended to

[1] [ALJ]'s Ruling Inviting Comments on Integration Capacity Analysis Methodologies, Integration Capacity Analysis Workshop Report, Locational Net Benefits Analysis Methodology, Locational Net Benefit Analysis Workshop and Demonstration Projects A and B, Feb. 18, 2016.

[2] The ICA Workshop report summarizes IOUs' and stakeholder presentations and discussions related to the ICA methodology and proposed dynamic ICA modelling under Demonstration Project A.

[3] The LNBA measures the value of DER based on its location on the distribution grid.

be utilized by third-party distributed energy resources (DERs) seeking to interconnect to the distribution system. The available capacity on the feeder will indicate whether DER can interconnect without triggering a system upgrade. It will also help IOUs target locations to evaluate DER interconnection as an alternative to traditional distribution system upgrade investments. DER providers access the ICA of distribution level feeders using online maps. The ICA of each IOU service territory will be updated by the IOUs on a monthly basis, with online ICA maps updated quarterly.

Demonstration Project A is a computer modelling exercise where IOUs apply their respective ICA methodologies to a subset of their service area. This Demonstration Project builds upon the ICA analysis the IOUs provided in the ICA maps published on July 1, 2015, as part of their initial DRP application. The ICA calculated in the July 1, 2015, maps is for a steady state system, where the ICA is a "snapshot" of the capacity at one given time, in a certain configuration. In Demonstration Project A, IOUs will model their demonstration areas in a dynamic state, which is consistent with day-to-day IOU operations. In the dynamic state, the IOU engineers reconfigure circuits to accommodate changing loads by opening and closing switches on the distribution system. The ICA model will calculate the capacity under two scenarios:

- The DER capacity does not cause power to flow beyond the substation busbar.
- The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system.

ORA's responses to questions posed in the Ruling regarding the ICA and Demonstration Project A are discussed below.

1. A detailed ICA methodology is missing from the ICA Report and should be submitted as a supplemental filing.

ICA Question 1. For non-IOU parties, please identify any substantive information from the workshop that is missing from the ICA report.

Parties expected the IOUs to provide detailed ICA methodologies as part of the ICA workshop. None were provided. This detailed ICA methodology is missing from IOU presentations. The IOUs should provide supplemental filings because ORA's preliminary evaluation of the IOU ICA methodologies show that the differences in IOUs' ICA methodologies are significant, but the impacts of the methodological differences are difficult to evaluate without additional information.

ORA recommends that IOUs provide a supplementary filing to the IOU Workshop report which includes: detailed ICA methodology, results, QA/QC procedures, and upgrade plans as they currently exist, and as they are planned to evolve. A supplemental filing should include the elements listed in Attachment A. This will aid in coordination with other IOUs, regulatory review, and internal tracking of the development and implementation of the ICA.

2. The IOU Workshop report misrepresents the extent to which IOUs detail their ICA methodology as well as the consistency and transparency between IOU ICA methodologies.

ICA Question 2. For non-IOU parties, does the workshop report misrepresent any statements made during the workshop?

While ORA did not identify any instances where the workshop report misrepresented statements made during the workshop, ORA finds that both statements in the workshop and the workshop report (Report) misrepresent the nature of the IOUs' ICA filings and the ICA tools themselves.[4] First, the IOUs state that they have provided parties an "unprecedented" amount of information detailing the intricacies of their ICA tools and methodology.[5] The implication is that the utilities have provided adequate information for stakeholders to vet the ICA tools and for the CPUC to approve them.

Second, the Report states "The IOUs' DRPs identify and summarize the performance of their respective ICAs using a common methodology."[6] This is consistent with the claim on slide 2 of the IOUs' workshop presentation. Differences between the IOUs' ICA tools appear significant, see Attachment B Section 11. These differences will likely prevent determination of comparable integration capacity (IC) values statewide and ICA results will continue to diverge, barring intervention by the Commission.

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[4] ORA uses the term "ICA tool" to refer to the complete ICA methodology used by each utility, including all third-party soft and custom software programs.

[5] Workshop report, p. 3.

[6] Id. at p. 6.

Third, the lack of detail provided by the IOUs to date creates a lack of cy. For example, the impact on the accuracy of IC values through PG&E's use of a streamlined methodology has not been provided, and is shrouded through reference to a proprietary EPRI report; see Attachment B Sections 1, 2 and 11.

3. Demonstration Project A should inform the correct level of granularity for the ICA.

ICA Question 3. Describe how the ICA can or should be modified to provide information on a less granular basis than the line section level, such as the aggregate integration capacity for an entire feeder or substation.

ORA understands there is a tension between the desire to refine granularity and the need to limit time and resource investment. In addition, the optimum balance of granularity to resource level could depend on how the results are used. For example, IOUs must balance the resources they expend in the Rule 21 interconnection process with resources spent planning for capital improvements in General Rate Cases (GRCs). However, ORA finds that determination of the optimal level of granularity for the ICA is not possible at this time. Demonstration Project A can and should help inform the correct level of granularity for a common ICA methodology.[7]

4. IOUs should justify inclusion or exclusion of IC values on single phase feeders since they comprise a significant portion of the IOUs' distribution systems.

ICA Question 4. Can the ICA be modified to include more information on single-phase feeders?

As noted in ORA's presentation at the ICA workshop on November 10th, PG&E's current ICA includes only 3-phase feeders, which excludes 49% of feeders based on total feeder length and 63% based on number of customers.[8,9] It is unclear to ORA if SCE's and SDG&E's

[7] This correctly implies that each ICA tool should ultimately have the same resolution.

[8] ORA data request ORA-004. Note that PG&E's system includes both one-phase and two-phase feeders, neither of which are currently included in PG&E's ICA.

[9] Joint IOU Workshop Report, p. 16.

approaches also examine only 3-phase feeders.[10] ORA supports ICA implementation at a reasonable pace and understands that not all system aspects, including 4 kilovolt (kV) feeders and secondary lines, can be implemented in the first version of the ICA tools. However, utilities should describe how and when non-3-phase feeders will be included in the DRP. If no such plans exist, IOUs should explain why modeling only 3-phase feeders is sufficient to provide the necessary accuracy and level of information required in this rulemaking. The optimal scope of ICA coverage should be addressed in the Demonstration Project A.[11]

5. ORA has no specific recommendations for reflecting load modification strategies.

ICA Question 5 Describe how the ICA can be modified to reflect load modification strategies such as demand response and efficiency combined with generation or storage. What assumptions should the utilities make regarding the operations of dispatchable DERs (e.g., storage and demand response)?

The definition of distributed energy resources (DER) includes a wide range of demand-side strategies such as energy efficiency (EE) and demand response (DR), yet most of the attention in ICA discussions targets solar photovoltaics (PV).[12] ORA currently has no specific comments or recommendations regarding this question, but addresses the more general question of how portfolios of DER should be included in the ICA in Attachment B, Section 7.

6. Information on the type and timing of thermal, voltage, reactance and protection limits is important for DER sourcing through the LNBA-IDER cost effectiveness calculator to ensure that DER value meets the required need and is not redundant.

ICA Question 6. Should the IOUs provide more information on the type and timing of the thermal, voltage, reactance, or protection limits that are responsible for limiting capacity hosting

[10] Joint IOU Workshop Report, p. 17 (SCE "will model actual load data from all three phases rather than just one phase," but does not specify a timeline or note whether this is load data only or all aspects of non-3-phase circuits.)

[11] IOU Demonstration Project A is expected to conclusively determine the optimum scope for circuits, but should provide evidence advancing consideration of this issue.

[12] For example, the EPRI report cited by the utilities as supporting their ICA methodologies is sub-titled "A Streamlined Approach for Solar Photovoltaics." PG&E DRP, p. 23 n.10.

capacity on each line? If so, what information specifically should the IOUs provide and in what format?

There is value in having ICA results include the source of IC limits (e.g., thermal, voltage, protection, safety/reliability) on each line section in addition to the limiting value because it can help guide specific distribution investments in GRCs or help determine the DER for valuation in the LNBA. The process for vetting and approving a common ICA methodology following Demonstration Project A should consider benefits and costs in determining the optimal content and format of ICA results.

7. IOUs should develop a reference circuit to show the consistency between IOU ICA methodologies and for reference when updating versions of the ICA methodology.

Demonstration Project A Question 1. Are there any specific recommendations for implementing Demonstration Projects A and B differently than proposed by the IOUs? Be specific in describing how different approaches would be implemented.

Demonstration Project A is a critical step in the development of consistent ICA tools. While the IOUs' current ICA methodologies are on diverging paths, Demonstration Project A can be the key to minimizing differences between the IOU methodologies. For example, PG&E's use of a streamlined EPRI methodology compared to the more iterative and computationally intensive methods of SDG&E and SCE, as discussed in detail in Attachment B sections 1, 2 and 11. Similarly, the proposed Demonstration A projects are independent projects with no stated provision to normalize the methodologies. If approved as proposed, the outcome of Demonstration A will likely be three significantly different ICA methodologies.

ORA recommends that Demonstration A projects be realigned to be consistent with the objective of developing a common methodology. Utility plans used to achieve this realignment should be an element of the supplemental filings ORA recommends in Attachment A. This realignment can only be achieved via Commission order prior to approval of the Demonstration A projects.

The supplemental IOU filings should also discuss how the following key elements of the ICA methodology will be optimized through Demonstration A projects within the overall context of the requirement for a common ICA methodology:

- Computation method: PG&E streamlined versus SCE "iterative nodal analysis" (see Attachment B sections 1, 2 and 11);
- Types of circuits to include: 3-phase 12 kV versus all primary and secondary;
- Temporal and spatial resolution of analysis;
- Temporal and spatial resolution of results; and
- Inclusion of the source of capacity limitations.

8. Success should be measured 1) through consistency on reference circuits and 2) according to ORA's twelve metrics of success and 3) through ORA's general benchmarks of success.

Demonstration Project A Question 2. How should the success of the demonstration projects be evaluated? What metrics should be used?

a) Determine success by showing ICA methodology consistency with a reference circuit.

The Commission should measure the ultimate success of Demonstration Project A by the extent to which IOUs create accurate and comparable IC values statewide. The IOUs should demonstrate how ICA results are verified and confirmed. While the IOUs indicated that some verification has already occurred[13] (for example, in planning for the Demonstration Project[14]), clear requirements for verification of technical details, assumptions, and accuracy of models should be established prior to the Commission authorization of Demonstration Project A. Verification could take multiple forms (e.g., accuracy of source data, basic modelling assumptions, and model responses to known conditions), but ORA recommends using a set of standardized "reference circuits" to perform "qualification testing" using a set of reference test cases.[15]

Differences between the results for each IOU could be deemed reasonable once vetted by stakeholders and the Commission. ORA envisions the qualification testing will quantify differences in IC values between IOUs and address potential methods to reduce these differences. The ability of these modeling runs to reveal how differences in utility design, rating,

[13] Joint IOU Workshop Report, page 7.

[14] Id. at page 17.

[15] The ultimate test of the accuracy of IC values would be testing on actual circuits whereby IC values are calculated iteratively as DER is added to a circuit until failures occur, but this is practical at many levels.

and operating standards impact the ability of its distribution system to absorb and utilize increasing amounts of DER is a valuable secondary benefit of this exercise. This information could be used to authorize an IOU requesting distribution modifications or upgrades and to modify the IOU standards that are deemed to be an unreasonable barrier to the state's DER objectives.

Rather than attempt to find real feeders at each IOU that could be considered equivalent, ORA recommends that a set of realistic but hypothetical reference circuits be created and used to compare IC results regardless of the methodology used to obtain them. Based on discovery and meetings with each IOU, ORA believes that reference circuits including realistic electrical characteristic, loads, and DER deployment can be uploaded to CYME (used by SCE and PG&E) and Synergi (used by SDG&E) to perform these tests. These reference circuits could also be used to check for adverse impacts due to changes in ICA tools over time.

ORA anticipates that the set of appropriate reference circuits will address:

1. Situations that trigger each IC limit criteria,[16]
2. Load levels, profiles, and distribution on the circuit,
3. DER levels, profiles, and distribution on the circuit,
4. Differences in typical equipment deployed by each utility, and
5. Differences in design, rating, and operation standards at each utility.

b) The Commission should adopt ORA's twelve metrics of success for the ICA.

ORA's workshop presentation included twelve criteria ORA believe must be met for the ICA to be deemed effective and consistent with Senate Bill (SB) 327. ICA's success increases with the achievement of each success criteria, which include the following:[17]

1. Accurate and meaningful results, [18]
2. Transparent methodology,
3. Uniform process that is consistently applied,

[16] For example, reference circuits that separately trigger thermal, voltage, protection, and safety/reliability limits must be included.

[17] Attachment D, pp. 12-13.

[18] Seven sub-criteria for "accurate and meaningful results" were provided on page 14 of the presentation.

4. Complete coverage of service territory,

5. Useful formats for results,

6. Consistent with industry, state, and federal standards,

7. Accommodates portfolios of DER on one feeder,

8. Reasonable resolution,

9. Easy to update based on improved and approved changes in methodology,

10. Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.)

11. Consistent methodologies[19] across large IOUs, and

12. Methodology accommodates variations in local distribution system.

c) *Additional benchmarks of success for demonstration projects generally.*

In addition, demonstration projects can be evaluated through the following benchmarks for success:

- Did the demonstration project create reliability concerns?
- Was the project cost-effective for ratepayers?
- Did the methodology accurately predict its intended result?
- Did the DER integrate in a timely fashion or did the capacity change so much by the time the project was implemented that it rendered the DER integration meaningless?
- Did the demonstration project reduce greenhouse emissions on the distribution grid?
- Is this project scalable?
- Does this project integrate with the IOUs existing systems?

[19] ORA suggests the definition specify that the following elements must be consistent for the methodologies to be deemed "common": scope, in terms of the types of circuits excluded; resolution of integration capacity calculations and results; methods to define loads; methods to define DER generation profiles; types of DER explicitly included in the analysis, including DER bundles or portfolios; calculation methods that provide the same level of accuracy and computational efficiency; IC limit criteria in terms of number and type of test performed; IC limit criteria, threshold values for each test performed; application of limits, i.e. how the results from individual tests are aggregated or compared to obtain a single IC value; information provided in result maps and tables..

ORA does not expect that demonstration projects meet all the criteria but the Commission should evaluate the ultimate "success" of the demonstration project by evaluating criteria such as these.

B. LNBA and Demonstration Project B

1. Background

As originally proposed in the Commission's Guidance document, the Commission requested IOUs to develop a locational net benefits test in their DRP filings that integrated DER into the IOUs distribution planning process.[20] Under the Guidance, IOUs are required to submit a unified locational net benefits analysis which "specifies the net benefit that DERs can provide in a given location."[21] Demonstration Project B was intended to model the optimal location benefit analysis methodology in one distribution planning area (DPA), with evaluation of at least near term (0-3 year project lead time) and one longer term (3 or more year lead time) distribution infrastructure project for possible deferral.[22] IOUs submitted LNBA proposals as part of their July 1, 2015 applications in consideration of the guidance.

Subsequent to the Guidance document, the bifurcation of the DRP and the IDER proceeding altered the scope of the DRP and, consequently, the requirements for the LNBA. On September 17, 2015, the IDER Decision (D.) 15-09-022 bifurcated the DRP proceeding by assigning the sourcing of DER under P.U. Code section 769(b)(2) and (3) to the IDER proceeding.[23]

In November 2015, the Energy Division (ED) staff submitted a DRP Roadmap Straw Proposal (ED DRP Roadmap), characterizing the role of the "DRP proceeding [as] primarily concerned with distribution grid planning and identifying enhancements required for optimal

[20] Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning (Final Guidance) (Feb. 6, 2016), Attach. pp 4-5.

[21] Id. at p. 4.

[22] Id. at p. 6.

[23] D.15-09-022, p. 8 ("The Commission initiated the [DRP proceeding] to establish policies, procedures, and rules to guide regulated energy utilities in developing their proposals required by public utilities Code Section 769. The goal of these proposals is to move a utility toward fuller integration of [DER] into its distribution grid planning, operations and investments. As further explained below, R.14-10-003 will not duplicate these efforts. Rather the two proceedings will work together to create an end-to-end framework from the customer side t the utility side of the grid, with this proceeding implementing Section 769(b)(2) and 769(b)(3)….").

placement and operation of [DER]."[24] The LNBA could also be used in the IDER proceeding to "potentially consider the issue of location-specific or service-specific pricing."[25] The ED DRP Roadmap proposed to divide consideration of the LNBA system-wide components to the IDER and left only the location-specific components of the LNBA to the DRP.[26] Under the ED DRP Roadmap, the IOUs "would use the existing methods for non-location-specific components [of the E3 DERAC model] until directed otherwise."[27] Modification to system-wide components of the LNBA would be deferred to the IDER proceeding.[28] Unspecified outputs from the DRP would feed into the IDER cost-effectiveness framework, which would assign the correct DER sourcing mechanisms.[29]

A February 26, 2016, Scoping Memo in the IDER proceeding summarized the role of the DRP as "develop[ing] methodologies to determine how distributed energy resources can meet system needs as an alternative to traditional investments, provide justification for meeting those needs with distributed energy resources instead of conventional alternatives, define the services that may be bought and sold to meet the needs, and produce maps that indicate where distributed energy resources should be sourced."[30] Additionally, "[Senate Bill (SB)] 350 enacted P.U. Code 454.51, which requires the CPUC to 'identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner.'"[31]

A CPUC Staff White Paper (Staff White Paper) related to the formation of Integrated Resources Plan (IRP) contemplates development of an "all source, all-technology valuation framework to apply to demand and supply-side resources," which is integrated through the IDER, PEV [plug-in electric vehicles], RPS [renewable portfolio standards], DRP and LTPP

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[24] ED DRP Roadmap, p. 5.

[25] Id. at p. 5-6.

[26] Id. at p. 18.

[27] Id. at p. 18.

[28] Id. at p. 18.

[29] Id. at p. 18.

[30] Joint Assigned Commissioner and [ALJ] Ruling and Amended Scoping Memo, Feb. 26, 2016, p. 6.

[31] ALJ Ruling Noticing Workshop, In the Matter of Public Workshops to initiate consideration of the Requirements established by Senate Bill 350 (De Leon), 2015, Nov. 13, 2015, p.1.

[long-term procurement plans] proceedings.[32] The Staff White Paper also proposed steps for integrated resources planning, which indicated the DRP as one of the proceedings to develop a proposed "integration subtractor" for demand side resources, which would apply to "determining the cost-effectiveness of resources such as demand response, energy efficiency (EE), energy storage (ES), and smart-inverter-based distributed generation (DG) that positively contribute to grid integration" under the assumption that "resources get credit for their positive contribution to integration."[33] Additional proposed tasks under the DRP proceeding include 1) creating a "declining [California Solar Initiative (CSI)]-type incentive structure for Storage- [solar photovoltaic (PV)] co-installations" through the [Self Generator Incentive Program (SGIP)], Storage and DRP Proceedings and 2) reconsidering [combined heat and power (CHP)] program benefits and costs through the CHP and DRP proceedings.[34]

An Order Instituting Rulemaking (OIR) on the Integrated Resources Proceeding listed development of "consistent methodologies for resource valuation and/or selection criteria across multiple resource types, for use in comparisons in all-source or multiple-source procurement" and "consistent cost-effectiveness analysis of demand side resources, as well as identification of demand-side resource potential" as important for analyses for the IRP process.[35]

2. The current IOU proposal is efficient for GRC integration of select distribution projects but too narrow to inform sourcing under the IDER and the IRP proceedings.

The task before the Commission is complex; the Commission wants one tool to find locational value for both distribution deferral purposes as well as more generally for valuation of DER on the grid in any form that provides the most cost-effective integration of DER.

IOUs propose to develop an LNBA analysis to a select handful of distribution deferral projects limits, setting technical requirements for DER to meet in order to defer the traditional distribution upgrade, and then sourcing the DER through request for offers (RFOs), and utilizing the DER alternative if it is cost-effective compared to the traditional distribution grid solution.

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[32] Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future, p. 51.

[33] Id. at p. 50.

[34] Id. at p. 51.

[35] IRP OIR, p. 15-16.

While the current proposal could be effective at quantifying the value of implementing a DER solution for the purposes of cost recovery through the GRC, it appears to be too narrow in scope to inform DER sourcing in the IDER proceeding because 1) the DERs incorporated through the handful of projects selected for distribution deferral is likely to include only a small portion of the 12,000 Megawatts of DER the Commission is seeking to integrate under the Clean Jobs Plan and SB 350 and 2) the scope is also too narrow because it presupposes that grid modernization upgrades will be implemented as traditional grid upgrades since DER solutions may be in direct competition with grid modernization investments as an alternative or deferral method to the grid modernization projects proposed.

ORA also considers limiting DER sourcing to IOU RFOs premature as it may exclude distribution deferral projects which would be cost-effective or practical only through alternative sourcing mechanisms which could be developed in the IDER. Therefore, ORA recommends that the LNBA developed as Demonstration Project B not limit LNBA analysis to areas which IOUs consider to be suitable for RFO sourcing projects.

3. The scope of the LNBA should allow valuation of DER as either positive, neutral or negative rather than assuming a positive impact.

Relevant commission proceedings assume that the value of DER on the grid is always positive. For example, the Staff White Paper on the IRP proposed that an integration subtractor be developed under the assumption that "resources get credit for their positive contribution to integration."[36] However, the main driver of DER integration is not cost-effectiveness, but GHG emissions reductions on the grid. SB 350 requires the CEC establish annual targets that will achieve a cumulative doubling of EE savings by 2030[37] with no requirement that there be cost savings necessary to implement the EE.

ORA recommends that DER valuation in the LBNA reflect the value to the grid regardless of whether the value is positive, neutral or negative. Mitigating the net negative effects of installing DER by location can be just as informative to DER sourcing as finding locations with

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[36] Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future, p 50.

[37] IRP OIR, p. 27.

an optimal positive benefit on the grid. Finally, understanding when negative or no value is added by placement of DER at a particular location on the grid furthers SB 350's goals of "optimal integration [of DER] in a cost-effective manner."[38] Failure to understand the true cost of DER integration can result inadvertently in inefficient policy making, overprocurement of specific resources or cost shifting.

4. DER valuation for grid services should be distinguished from the value at which DER is compensated on the grid.

ORA recognizes that certain DERs possess power quality or reliability services. At the LNBA workshop, IOUs correctly pointed out that if the DER functionality does not affect the function of the distribution grid hardware, it would be double counting to compensate DER for services that DER do not contribute to enhancing the grid. Likewise, compensating DER for grid services that fail to avoid the need for traditional grid investments, due to their intermittency or other critical lack of functionality, should not be compensated based on its ability to partially meet the grid's reliability needs. Compensating DER for unneeded service requires ratepayers to pay twice for the same service. ORA recommends that an LNBA model which thoroughly and transparently evaluates grid functionality needs on either the feeder or the substation level, whichever is appropriate, is important for identifying DER functionality that addresses the proper need, whether it is a capacity limitation or exceedance of reliability or resiliency criteria.

5. Expansion of Community Choice Aggregators (CCAs) as well as local government planning requires a tool that allows transparency of DER impacts on the local distribution grid and transmission impacts. Local energy service providers (ESPs) should be able to choose more GHG reduction and pay for incremental grid expenses through a cost allocation mechanism.

A transparent and uniform methodology for the LNBA is also necessary to address the grid impacts from CCA that are seeking to implement aggressive greenhouse gas reduction programs or local governments looking to integrate DER as part of their climate action plans. Without an effective tool to measure the effects of their programs on the distribution grid, CCAs and local governments will not be able to assess the cost or value of integrating additional DER on the

[38] SB 350 (De Leon) (2015).

distribution grid. Using the LNBA as a baseline for the value of the traditional grid costs without DER, the CCAs and local governments can satisfy their obligations under Public Utilities (P.U.) Code section 451.51, which requires the Commission to "ensure that the net costs of any incremental renewable energy integration costs procured by an electrical corporation to satisfy the need [to procure a portfolio of resources to achieve greenhouse gas emissions pursuant to the Global Warming Solutions Act] are allocated on a fully nonbypassable basis," that "bundled customers will be indifferent to the CCA proposals" and "costs from nonperformance will be borne by the electrical corporation or CCA responsible for them."[39]

6. ORA recommends the current LNBA methodology incorporate a tool that allows grid needs to be assessed as a screening tool to match DER functionality with grid needs.

The LNBA proposed output is heat maps showing select locations which could provide positive value on the distribution grid through DER integration for the purposes of traditional grid investment deferral. The value to the grid, however, should be secondary to identifying the grid functionality needs. Once grid functionality need is appropriately characterized, the tool can calculate its value. Currently DER is a solution looking for a problem. Ideally, the LNBA tool will help steer DER technology innovation towards the most pressing grid needs by identifying those needs. Otherwise, DER technology innovation will gravitate towards the easiest feature to integrate, which may not be the most cost effective for ratepayers. Again, a transparent and user friendly LNBA methodology will allow and the Commission to match IDER functionality with grid needs most effectively. Transparency could be enhanced by allowing each type of grid need to be evaluated independently rather than as a single value for a location. For example, the input could be evaluated separately by selecting the input layer. Ideally, the LNBA tool could evaluate the traditional cost of addressing grid concerns by selecting a geographic area as well as the grid concern that DER hopes to address.

[39] IRP OIR, p. 22-23.

7. Circuits where reliability concerns are addressed through traditional distribution upgrades due to aging infrastructure could be a separate screen in the LNBA

As a separate screening, the IOUs could remove feeders with capacity constraints and reliability concerns that must be replaced with traditional infrastructure investments due to their age. Identification of those circuits geographically will help steer DER providers to locations where DER integration value is more likely to be cost-effective and will also facilitate GRC review for the Commission when approving distribution upgrade costs.

8. Location-specific inputs in the LNBA should be unified across IOUs.

The categorization of inputs for DER location-specific values vary widely and should be consolidated for effective integration with the IDER analysis, which may modify non-location specific aspects of the LNBA. The following represents categories of location-specific LNBA components from the IOU DRP filings as identified in the LNBA workshop:

<u>SDG&E</u>
- Transmission and Distribution (T&D) Capacity
- Distribution Reliability/ Resiliency

<u>PG&E</u>
- Distribution Capacity
- Transmission Capital and Operating Expenditures
- Voltage and Power Quality
- Reliability and Resiliency

<u>SCE</u>
-T&D Capacity Expansion Deferral
- Distribution P.Q. capital and Operation and Maintenance (O&M)
- Distribution Reliability & Resiliency Capital and O&M

ORA recommends that the locational inputs be unified among IOUs so that the IDER analysis can look at location value across all three IOUs in a consistent manner.

III. CONCLUSION

ORA respectfully submits these comments and recommends that the CPUC adopt ORA's recommendations.

Respectfully submitted,

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March 3, 2016

ATTACHMENT A

The following should be included in the ORA recommended Supplemental Filings.

First, the filings for each individual utility should include the following:

1) Additional documentation regarding its current ICA methodology including:
   a) A flow chart of the ICA process,[1]
   b) Flow chart of the ICA tool that shows how commercial products within the tool interact with custom components,
   c) If a "streamlined" method is used, define the process used, including all assumption used and anticipated impacts on ICA accuracy,
   d) How analysis at the nodal level is used to determine feeder IC values,
   e) Definition of how short-circuit response vs. load flow analyses are used,
   f) QA/QC procedures for any custom software, including revision control,
   g) Details on IC limit criteria, threshold values, and how they are applied,
   h) Explanation of the industry, state, and federal standards embedded within the ICA limitation criteria
   i) Electronic files that allow the CPUC and parties to view and validate inputs, models, limit criteria, and results.

2) Detailed plans for achieving and verifying that the ICA tools resulting from Demonstration Project A will meet ORA proposed or consensus success criteria, including:
   a) Plan to close the methodological gap between individual ICA tools,
   b) Schedule/Gantt chart of the ICA development process, and the external work required to support it. For example, if ICA development relies on SCADA build out or development of modeling or forecasting tools, these should be included.
   c) Additional Demonstration Project A details including goals, deliverables, issued to be tested, ICA methodology and tool configuration to be tested.
   d) Plan for the inclusion of the following:
      i) DER bundles or portfolios,
      ii) Newly installed DER
      iii) Smart inverters

[1] For example, see ORA's ICA workshop presentation, slides 6-11.

iv) Use of smart meter data to develop more localized load shapes

e) ICA validation plans, including reference to ORA's proposed qualification testing

Second, ORA recommends that the utilities jointly prepare and submit to the docket an exhibit that compares the following:

a) The list of consistent elements from the proposed detailed definition of a common ICA methodology,
b) The state of each utility methodology relative the common elements,

   For each of the common elements, provide an objective evaluation of the degree to which the ICA methodologies are consistent, including a simple metric such as "not at all, somewhat, entirely" to indicate the level of consistency.

Third, ORA recommends the joint filing include multiple comparisons based on the methodologies at different point in the near term: as filed in the DRP, currently, as planned for Demonstration Project A, prior to full implementation and use. Ideally this will illustrate how and when a common methodology will be attained. This filing should be subjected to stakeholder review prior to authorization of Demonstration A projects. ORA also recommends IOUs update this comparison exhibit regularly so the Commission and stakeholder can track each IOU's progress. Each filings should be subjected to stakeholder review prior to authorization of Demonstration A projects.

ATTACHMENT B

Critique of Current ICA Tools and Utility Workshop Presentation on ICA

I. Summary of Utility ICA Presentation

The utility joint presentation regarding ICA can generally be described as a high level summary of ICA tools, methods, results, and next steps, with only two slides to discuss the methodology on three utility tools.[1] The presentation provided some information beyond that provided in the DRPs but left significant questions about the ICA methodology, plans for upgrading the ICAs and Demonstration Project A. It is apparent that differences exist between each utilities ICA and its state of development. ORA finds these differences to be significant and the current ICAs fail to meet to CPUC directive for "a common methodology across all Utilities."[2] ORA's critique of the current ICAs below is based on the criteria listed in ORA's workshop presentation.[3]

II. Critique of Utility ICA Tools Relative to ORA's Proposed Success Criteria

ORA's ICA workshop presentation included 12 criteria that were proposed to evaluate utility ICA tools, methodologies and results.[4] This section compares the currently proposed utility ICA tools against each of these criteria.

A. Accurate and meaningful results

Current ICA results should not be considered as accurate and plans to make them accurate have not been provided. ORA's workshop presentation outlined seven sub-criteria for determining if ICA results are accurate and meaningful, see Attachment D slide 14.[5] Based on the

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[1] *See* Integration Capacity Analysis Workshop (11/10/15): California IOU's Approach (Nov. 10, 2015), slides 4-5.

[2] Assigned Commissioner Ruling (Feb. 6, 2015), att. p. 3.

[3] It is important to distinguish current ICAs, those filed on July 1, 2015, from versions that may have evolved since then or that utilities would like to develop through the Demonstration A projects or afterward.

[4] The twelve criteria include, 1) accurate and meaningful results, 2) transparent methodology 3) uniform process that is consistently applied 4) complete coverage of the service territory 5) useful formats for results 6) results consistent with industry, state and federal standards, 7) accommodates portfolios of DER in one feeder 8) reasonable resolution 9) easy to update based on approved and improved methodology 10) easy to update based on changes to inputs 11) consistent methodologies across large IOUs and 12) methodology accommodates variations in local distribution systems such that case-by-case distribution planning area (DPA) adjustments are not needed.

[5] XXXXXX

limited information provided by the utilities to date, it is not possible to determine if the ICA values are accurate or meaningful. During the workshop, Tam Hunt of Community Renewable Solutions expressed concern that the results for SCE were overly conservative and Energy Division responded "ICA methodologies are not yet approved and stakeholders should not have an expectation of accuracy for commercial decision-making."[6] PG&E's DRP provides a diagram showing their ICA as providing a balance between accuracy and speed of analysis but neither the DRP, utility workshop presentation, nor the workshop report quantify the impact of having the analysis provide anything less than the highest level of accuracy.[7] An EPRI report provided in response to ORA discovery includes a revised version of PG&E's diagram showing that "ERPI's Streamlined Method" now provides higher accuracy and speed and a claim that it "determines distribution impacts more quickly without compromising accuracy," but provides no data to support this assertion.[8] The report does indicate that the streamlined method is based on trends from previous studies on hosting capacity for PV, which raises questions about how well the methods is suited to other DER technologies and suggests that feeder level results depict a "worst-case scenario."[9]

While ORA's discovery has yielded some insight into each utility's ICA, the information is insufficient at this point for a determination of adequate accuracy of the current ICA tools. More importantly, the utilities have not described the overall process, specific quality control steps and validation/testing plans that they will use to ensure that the final ICA tools and results are accurate. ORA's post-workshop comments recommend supplemental utility filings to provide additional information to allow ex-ante determination of the probability of accurate results and qualification testing to provide the ultimate evaluation of ex-post accuracy.

B. Transparent methodology

Utility filings and presentations to date have not provided the transparency required to review, vet or approve the ICA methodology as final. ORA had anticipated that a detailed

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[6] This is a specific example of the general stakeholder input provided on page 3 of the Joint IOU Workshop Report, Attachment A to Administration Law Judge Ruling in R.14-08-013 dated February 18, 2016.

[7] PG&E DRP submitted July 1, 2015 in R.14-08-013 (PG&E DRP), Figure 2-1, p. 24.

[8] EPRI, Integration of Hosting Capacity Analysis into Distribution Planning Tools (Jan. 2016), p. 5.

[9] *Id.*, pp. 5-7.

methodology would be provided by each utility at the workshop for review but none was provided. ORA was able to greatly expand its understanding of ICA tools and methodologies through the discovery process but knowledge gleaned through the discovery process should not be confused with transparency by the utilities.[10] The discovery process places the burden of proof and documentation on the parties and CPUC rather than the utilities, who have the statutory burden of demonstrating that they have complied with CPUC guidance. One example of the lack of transparency is that PG&E describes that is used is a "streamlined approach to identifying available capacity" similar to a method developed by EPRI but does not discuss what was streamlined and how this impacted the accuracy and consistency of the results.[11] PG&E cites to a 2014 EPRI study which is proprietary and it is not clear if this is the same method discussed in the 2016 public EPRI report previously mentioned. The 2014 EPRI study does discuss how streamlining impacted accuracy, but it was difficult for ORA to gain access to this report and the results are proprietary.[12]

C. Uniform process that is consistently applied

Automated "batch processing" should be used where practical but only using production versions of software which are fully tested and subjected routine revision control. ORA conceptually supports the portion of PG&E's methodology where objective tests are applied uniformly via computer code through batch processing, assuming that PG&E's software tools have advanced through testing and validation phases of a waterfall model of software development and have been released to production.[13,14] Alternative software development models such as "Ag-

[10] PG&E provided an example of such a presentation in response to ORA DR-004-Q8, and supplemented this in a presentation to ORA and TURN on February 16, 2019. SDG&E and SCE provided additional details in presentations to ORA on February 5 and 19 respectively.

[11] PG&E DRP, p. 23.

[12] EPRI charges $10,000 for access this report. See http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?productId=000000003002003278.

ORA first requested this report from PG&E on September 22, 2015 in DR-ORA-PG&E-DRP-004 Q8, but only received a confidential copy from SCE on February 24, 2016 in response to DR-ORA-SCE-DRP-002 Q7, issued January 8, 2016.

[13] *See* https://en.wikipedia.org/wiki/Waterfall_model.

[14] Based on discussions during the workshop, it appears that all utilities are moving towards batch-processing to improve scalability. *See* Integration Capacity Analysis Workshop (11/10/15): California IOU's Approach (Nov. 10, 2015), slide 3; Joint IOU Workshop Report, p. 7.

ile," however, may be appropriate. Therefore, production-ready software may not be required for Demonstration Project A. Any models should be used consistently and utilities should accurately document versions of all software used for ICA analysis.

D. Complete coverage of service territory

The current ICA excludes significant portions of utility customers and distribution service area, and it is not clear when and if these exclusions will be removed. PG&E's DRP can be interpreted as stating that its initial ICA covers all distribution circuits in its service area, with a few minor exceptions.[15] ORA's discovery, however, revealed that one exception -- limiting the scope to 3-phase circuits -- leaves out approximately half of its potential DER locations.[16] SCE and SDG&E also exclude certain portions of the distribution system.[17]

ORA recommends that providing IC values for every potential DER location on the distribution system be the baseline goal for each ICA. Each utility should explicitly define the limitations of its analysis, describe how and when each limitation will be removed, and provide justification for any limitations it does not plan to remove. While it may be reasonable that Demonstration A projects will be performed on a limited portion of the distribution system, the CPUC and parties should have information from the utilities that places these projects within the context of full coverage of its service territory.

E. Useful formats for results

Map navigation and legends need to be clear and uniform, and maps should be searchable. The utilities' Integrated Capacity Analysis maps vary greatly in level of detail,[18] appearance, searchability, underlying platform,[19] access restrictions,[20] and many other factors. For ex-

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[15] "PG&E was able to conduct dynamic analyses for all relevant distribution feeders down to the line section level," PG&E DRP Application, p. 60.

[16] One and two phase feeders provide 49% of PG&E's feeder length and 63% of its customers takes service on these circuits. See Joint IOU Workshop Report, p.16; PG&E Data Request, DR-ORA-DRP-PG&E-3-Q2, Q3.

[17] SDG&E's July 1, 2015 filing included only 3-phase 12 kV feeders, per response to DR-ORA-SDGE-2-Q11. SCE "currently excludes three-phase, non-mainline conductor," per response to DR-ORA-SCE-2-Q11.

[18] Joint IOU Workshop Report, pp. 10-11.

[19] For example, SDG&E and SCE's ICA Maps use ArcGIS, while PG&E appears based on Google Maps.

[20] For example, PG&E requires a PG&E login, SDG&E requires a specially-granted account, and SCE has no access restrictions.

ample, PG&E generally provides 20 values for each zone, two values for each of ten DER options. PG&E's map provides IC values in response to user "clicks" on a map, but does not allow searches based on an address or particular feeder and zone ID. The ability to compare ICA maps and analyses in the DRP will be critical to draw correct and useful conclusions, and to further refine the ICA and Locational Benefits process.

While the three utilities may have differing needs, technological capabilities, and preferred processes for creating and maintaining their ICA maps,[21] basic aspects and components of the maps should be standardized for ease of use and ease of comparison. Examples of such components could include but are not limited to: presence of map legends/keys with quantitative descriptors; standardized legends/keys, standardized visuals (for example, capacity color gradients), clear and appropriate navigation tools; reasonable resolution at high and low zoom levels; and reasonable loading time at high and low zoom levels.

ICA maps should also be searchable. Both locational and technical criteria should be findable by an efficient and accurate search tool. For example, users should be able to find a specific address or street by searching, as well as a specific feeder or circuit number. ORA recommends searchability through the map interface itself and not in a separate database.

Results from each ICA tool should be directly useable by end-users in the Rule 21, GRC, DRP, and IDER proceedings. Each utility has provided results in online map and spreadsheet formats. The utility of the ICA results will depend on how the data is used, and encompasses the values provided as well as how they are presented. ORA recommends that the ICA result values and the format of these values should evolve in concert with the methodology itself to ensure that the intended uses of the ICAs are fully supported.

F. Results consistent with industry, state, and federal standards

As these ICAs will be used to guide investment and interconnection consistent with these industry and government standards, it would aid the CPUC and parties if each standard embedded within (i.e. as a test criteria) the ICAs were specified. Without additional information, ORA cannot evaluate whether ICA criteria and results are consistent with applicable standards. The ICAs relate to a physical electrical distribution system that is designed and maintained in ac-

[21] *See* Joint IOU Workshop Report, p. 7.

cordance with industry standards (IEEE 1366-2012 and 1547), state orders and rules (e.g. CPUC General Order 95), and federal standards (ANSI C84). ORA is currently developing its knowledge of electric distribution standards and is not able to catalog the standards which are relevant and applicable to the ICAs at this time.

Each major utility is subject to the same mandatory or minimum standards. Where an individual utility adopts internal standards that exceed universal standards, it does so voluntarily and subject to CPUC regulation. Utility specific internal standards should be reviewed through the lens of the state's policy objectives; in this case facilitation of DER integration.[22]

G. Accommodates portfolios of DER on one feeder

The current ICAs do not provide integration capacity based on portfolios of DER or "DER bundles." One of the stated objectives of the ICA per the CPUC is to "build the capabilities to compare portfolios of DERs as alternatives to traditional grid infrastructure."[23] Currently, only PG&E has the ability to capture the impact of various types of DER on feeder[24] but it does not allow for a user-defined portfolio of DER to be compared to feeder capacity. PG&E's ICA map includes the ability to view "Minimal Impacts" and "Possible Impacts" levels for feeders were certain technology "bundles" to be integrated.[25] These bundles include "Uniform Generation (Inverter)," "Uniform Load," "PV," "PV with Storage," "PV with Tracker," "EV – Residential (EV Rate)," "EV Workplace" and others. It is unclear whether SCE and SDG&E use similar bundles or a similar approach.

The utilities should provide further clarity on the use of DER bundles and how they are created, calculated, interact with each other, and will be updated. It is unclear whether the bundles' capacities are interactive and related (i.e. integration of one type of bundle will change

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[22] For example, utilities have an internal goal of maximizing reliability as measured by System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), as defined and measured by Institute of Electrical and Electronic Engineers (IEEE) 21 Standard 1366-2012. The utility goal is to reduce the duration and frequency of outages and continuously reduce these performance metrics but an acceptable minimum values is not defined. *See* A.15-09-001, Exhibit PG&E-4, pp. 9-7 to 9-11 (Establishment of minimum reliability targets could allow better integration of DER while still providing acceptable service to customers).

[23] CPUC, DRP [R.14-08-013] Workshop: ICA and Demonstration Project A (Nov. 10, 2015), slide 7.

[24] PG&E uses provides IC values based on ten separate DER/load profiles (Figure 2-15) while SCE and SDG&E use only the peak capacity of DER in ICA modeling, so the type of DER is not a factor.

[25] Joint IOU Workshop Report, p. 6.

available capacity for others), non-interactive with upper limits (i.e. "buckets" to be filled independently), or some other third option. Utilities should provide clear documentation on how bundles are created and defined. In addition, utilities should provide information on how each bundle capacity will be updated[26] when DER is integrated onto a given feeder.

H. Reasonable resolution - Optimum resolution should be developed as Demonstration Project A.

Resolution of ICA inputs and results currently varies widely. The optimum resolution should be determined as part of ICA tool development. There is a great diversity of load throughout each utilities' service territory. The temporal resolution (or time-step) will change over the course of geography and the course of the day/time of year. For example, in a residential area where the majority of individuals work from 8:00 a.m. to 5:00 p.m., the load may be nearly constant during working hours and the temporal resolution may be in hour increments, but the granularity of the temporal resolution will change once residents arrive from work and start turning on load. The ICA should conceivably be able to change the time-step required for updates based on changing customer behavior. The same is true for geographic diversity (the length scale). In a rural area, where load may be non-existent for an extended area, the length scale may be miles, where as in an urban area, the length scale may need to be more granular to capture the variability in load. As a first step, the utilities should explain how data granularity level was chosen and whether higher granularity is possible, and if so, what tools are needed to implement it and how fast can the ICA be updated with higher level of granularity.

As discussed in the workshop, there is a tension between high levels of resolution and the time and effort to run the analyses. This is an issue that will be resolved as the methodologies mature and is an issue to be tested in Demonstration Project A. ORA recommends that input be solicited from DER developers and other potential ICA users to ensure that sufficient resolution is provided.

I. Easy to update tools

ORA is unable to comment on this detail of the ICA methodologies due to insufficient information. Development of the ICA tools appear to be an evolutionary process that will contin-

[26] See Joint IOU Workshop Report, p. 14.

ue beyond the Demonstration A projects and initial approval by the CPUC. ORA recommends that a revision control system be implemented to annotate and archive ICA revisions as the methodologies evolve over time.

J. Easy to update results

ORA is unable to comment on this detail of the ICA methodologies due to insufficient information. In addition to the methodological changes discussed in Section 9 above, ICA results will evolve as feeder components are replaced/upgraded, circuit topography changes, DER is deployed with and without smart inverters, and loads change. The ICA should be capable of updates based on these types of changes. ORA recommends that the revision control system discussed above include annotation and archiving of results as well as methodology such that changes in integration capacity statewide can be tracked, and ICA users have a reference for past results that were used in decision-making.

K. Consistent methodologies across large utilities

Based on information provided to date, the ICA tool from each utility does not use a common methodology. The utilities have repeatedly stated that their ICAs are based on common methodologies, consistent with the CPUC direction/guidance.[27] Based on the utility workshop presentation and ORA's discovery to date, we do not agree. The following are some of the significant differences between the methodologies used by each utility:

- Computation method: PG&E "streamlined" method[28] (see Attachment E) vs. SCE "iterative nodal analysis (see Attachment F),"[29]
- Spatial resolution per feeder: SDG&E 3, SCE 4, PG&E 5,
- IC limitation tests: only PG&E includes islanding test; different terms used for protection tests as PG&E uses the term "reduction of reach"[30]

[27] Assigned Commissioner Ruling in R.14-08-013 (Feb. 6, 2015), Attachment, p. 3; Joint IOU ICA Presentation (Nov. 10, 2015), slide 2; Joint IOU Workshop Report, p. 6.

[28] PG&E, PG&E's Distribution Resource Plan: Details on Integration Capacity Analysis (Jan. 2016), slides 31-34.

[29] SCE, SCE ICA Webinar (Feb. 19, 2016), slide 3.

[30] PG&E, Distribution Resource Plan: Details on Integration Capacity Analysis (Jan. 2016), slide 27.

while SCE uses the term "breaker reach limitation"[31] and SDG&E uses the term "fault interrupting capability,"[32] see Attachment G.

- Application of limitation criteria: PG&E formulas vs. SCE standards embedded in CYMEdist.
- Incorporation of DER profiles: PG&E uses ten (10) profiles while SDG&E and SCE do not rely on profiles.

Of particular concern is the distinction between PG&E's use of a "streamlined" methodology versus the "iterative nodal analysis" used by SCE, since these result in a different balance between accuracy and speed of analysis. In addition, PG&E's formulaic IC limitation criteria have the advantage of transparency and consistency, but may sacrifice the ability to accommodate differences in the characteristics of each feeder, thus limiting accuracy.

ORA understands that small differences may persist in the results from individual ICA tools based on differences in utility standards and hardware, but these should be the exception and not the norm. In addition, all utilities must comply with the same technical and regulatory standards in operating their distribution systems, and these common standards apply to all sizes, types, and location of customer. Unless proven to the contrary, the CPUC should expect comparable ICA results from each utility for a comparable circuit, and ORA's recommendations include qualification testing for this purpose.

L. Methodology accommodates variations in local distribution systems, such that case by case or distribution planning area (DPA) specific modifications are <u>not</u> needed

ORA is unable to comment on this detail of the ICA methodologies due to insufficient information. In addition, it is possible that there will be tension between a methodology that is automated and consistent versus one that provides for exceptions where the standardized tools do not apply. ORA recommends utilities consider this issue during the development of ICA batch processing and provide a summary of batching methodology in the supplemental filing.

[31] SCE, ICA Webinar (Feb. 19, 2016), slide 4.

[32] SDG&E, Distribution Resources Plan ICA Deep Dive, slide 6.

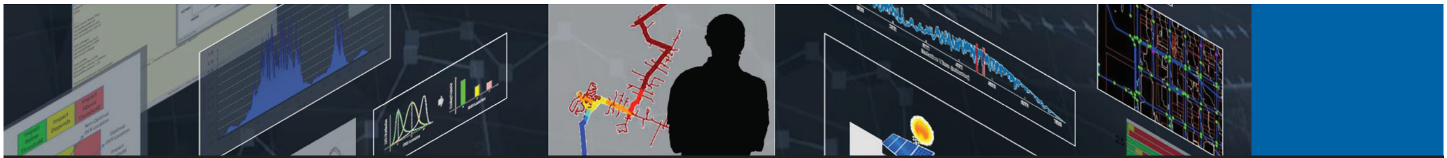
ATTACHMENT C

Electric Power Research Institute (EPRI), Integration of Hosting Capacity Analysis into Distribution Planning Tools, January 2016.

ELECTRIC POWER
RESEARCH INSTITUTE

INTEGRATION OF HOSTING CAPACITY ANALYSIS INTO DISTRIBUTION PLANNING TOOLS

January 2016



Introduction

Distribution planners are being faced with a new reality – the vast majority of change to the distribution system is occurring due to the addition of distributed energy resources (DER). The result is a new set of challenges when planning and integrating DER. Just as capacity planning studies are performed for accommodating new load, hosting capacity planning studies are needed for accommodating new DER. To meet this challenge, the industry needs a system-wide method to plan for and integrate DER into the distribution system.

Providing safe, reliable, and affordable service to all customers is paramount. With the addition of DER, utility engineers must ensure it does not adversely impact power quality or reliability. Currently, techniques like interconnection screening simply do not give utilities the visibility they need into the potential impacts of DER across their distribution service territory. Furthermore, performing a detailed study requires a great deal of data and time. In lieu of these drawbacks, distribution engineers still need to understand: How much DER can be accommodated, what potential issues may arise over time, as well as where DER can be more optimally located to avoid infrastructure upgrades in order to better plan for and integrate DER. On top of these outcomes, distribution engineers are also faced with additional regulatory pressures to provide further information.

The New Reality

"The IOUs are required to define locational benefits and optimal locations for DERs...moving the IOUs towards a more full integration of DERs into their distribution system planning, operations and investment.

– CA PUC Code 769, Aug 2014

"The more efficient system will be designed and operated to make optimal use of cleaner and more efficient generation technologies and will encourage substantial increases in deployment of these technologies...DER will become integral tools in the planning, management and operation of the electric system.

– NY REV, Feb 2015

A critical aspect to help meet these challenges is to have a clearer understanding of the distribution system's ability to host DER using available data, models, and tools utilities use today. This "hosting capacity" of a distribution system is the amount of DER that can be accommodated without adversely impacting power quality or reliability. Hosting capacity can vary along a distribution feeder, across a range of feeders, and can change over time as the distribution system infrastructure changes and incorporates more DER.

With a tool developed around this critical aspect, more effective and efficient screening can be performed, better or worse locations for DER can be identified, and planners can better understand where and how DER impacts the entire distribution system. When combined with long-term DER forecasts, utilities can better evaluate where infrastructure upgrades are going to be required and incorporate this information into the overall strategic decision making process. In addition, once hosting capacity is determined it can be used as input to better understand where DER can bring value to the distribution system by providing services when and where they are needed.

State of the Industry

In the not-too-distant past, distribution planners had fewer interconnection requests and were able to analyze each DER application individually. More recently as applications have increased exponentially, utilities have begun employing fast-track methods like the "15% rule" for peak feeder load in order to process the large number of applications. These are intended to be conservative methods, but have taken the dependence on actual feeder characteristics out of the equation. Cognizant of the importance of factors that vary widely among feeders, some utilities have looked towards clustering feeders based upon topology and model/analyze a single (representative) feeder from each feeder "cluster." Each of these methods seeks to overcome the intensive labor needs, complexity issues, and extensive data inputs required to perform a rigorous analysis on each individual feeder.

Table of Contents

This white paper was prepared by Jeff Smith, Program Manager, Power System Studies, EPRI; Matthew Rylander, Technical Leader, Power System Studies, EPRI; and Lindsey Rogers, Project Manager, EPRI.

However, EPRI analysis has shown that percent-load screens and feeder clustering may not accurately reflect how much DER a feeder can host [1,2]. Improved methods are needed that enable utilities to *effectively* and *efficiently* evaluate the entire distribution system with DER.

The industry has begun to explore new methods to consider these resources in the planning process. Most recently in California, the IOUs filed Distribution Resource Plans documenting different approaches. While each of these approaches have similar goals, the actual implementation varies considerably based upon the extent of data and models readily available for analysis.

Since 2014, EPRI has been working to develop, streamline, and validate newer methods for determining hosting capacity using readily available utility data and tools. These new methods build on the detailed work done with PV, and since expanded, to consider hosting capacity of any DER across a range of distribution impacts considered by utilities.

This white paper will describe the streamlined hosting capacity method developed by EPRI, the implementation of that method in distribution planning tools, and the data needed to successfully use this method to determine distribution-wide hosting capacity.

Considerations for an Effective Method

In analyzing dozens of feeders across the U.S. [3], one thing is abundantly clear – the amount of DER that can be accommodated without upgrading the system varies between distribution systems and on feeders within a system. The main factors that drive the amount of DER that can be hosted, without necessitating changes to the grid, are: 1) DER location, 2) feeder design and operation, and 3) DER technology.

These main factors can result in a wide range of feeder hosting capacity thresholds. The interactive effects are important because in some cases, increasing levels of DER can produce a positive collateral effect, while in others it does not.

DER Location

Location, location, location…

The hosting capacity for any feeder is not one single value but a range of values that depend upon a number of factors, mainly DER location. An effective method must consider all possible single, centralized locations along a feeder as well as the aggregate impacts of highly distributed DER. Also inherent to DER location is the consideration of phasing of the feeder at that location, i.e., connected to the three-phase main trunk or a single-phase lateral.

EPRI research has shown that significant levels of small DER spread throughout a single distribution feeder can have a considerable impact on the distribution system performance. This is often neglected in many studies. Likewise, the impact of large centralized DER has been shown to have a significant but widely varying impact depending upon where it is located along the distribution system [3]. Effective hosting capacity methods should consider a wide variety of location-based DER scenarios.

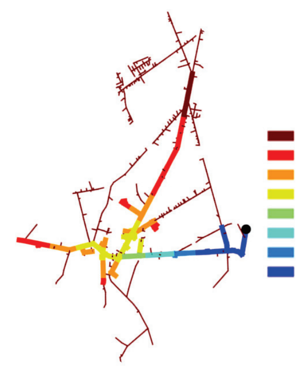


Figure 1 – The Location

Feeder Design and Operation

Distribution feeder characteristics also determine how much DER can be hosted. Voltage class, feeder topology, and load location are just some of the factors that determine what level can be accommodated and where. Additionally, the operation of the system, like voltage control schemes and radial/network topology, can have an impact on the amount of DER that can be accommodated and where.

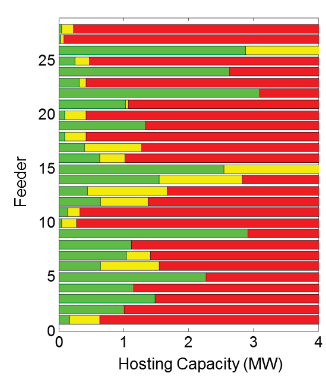


Figure 2 – The Feeder

The actual feeder design and operation includes a significant number of characteristics. These characteristics result in a dynamic interaction that must be examined in the power flow solution of the complete feeder model.

[1] Alternatives to the 15% Rule: Final Project Summary. EPRI, Palo Alto, CA: 2015. 3002006594.
[2] Determining the Effectiveness of Feeder Clustering Techniques for Identifying Hosting Capacity for DER. EPRI, Palo Alto, CA: 2015. 3002005795.
[3] Distributed Photovoltaic Feeder Analysis: Preliminary Findings from Hosting Capacity Analysis of 18 Distribution Feeders. EPRI, Palo Alto, CA: 2013. 3002001245.

DER Technology

The type of DER is another critical component since variable DER such as solar and wind have a vastly different distribution impact when compared to other forms of dispatchable DER such as energy storage. The differences primarily emanate from the ability, or lack thereof, to control the DER and when the DER is available. Care must be taken when considering specific technologies and how they interact with the grid.

Variable generation such as solar and wind are similar in that they are for the most part non-dispatchable resources. Even though they are both an intermittent resource their impact to the system is dependent on the time of day they provide power. Solar generation is constrained to daylight hours, while wind is not. The impact to the grid can also be vastly different based on their energy conversion technology. Inverter-based solar generation typically has a low fault contribution while wind generation is dependent on the turbine technology.

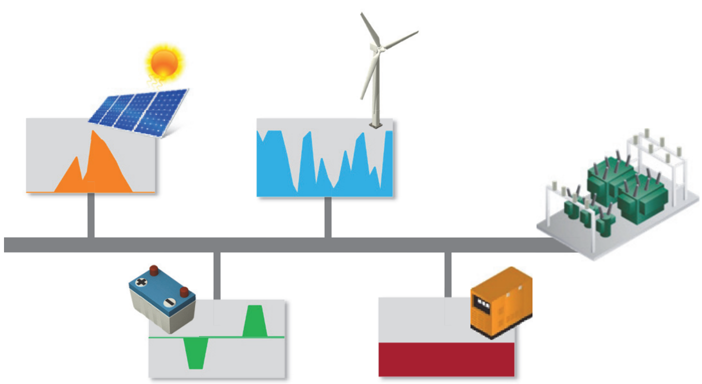


Figure 3 – The Technology

Energy storage is often considered as a solution to many intermittent resource problems, and although energy storage can provide such a solution, the technology comes with its own set of impacts that must be considered. The mode by which energy storage is used can have a widely varying impact to the grid. Such mode could be 1) unconstrained based on the resource owner's discretion, 2) constrained based on the market use of the resource, or 3) utility-controlled based on the utility knowledge and control of the resource. Each mode presents its own set of impacts to the system and should be examined uniquely.

The impact of inverter-based technologies can change when advanced inverters that have additional grid support functionality are used. In some cases, this functionality can help reduce the impact of the intermittent resource by providing voltage support. However, advanced inverters don't always reduce impact. Identifying the appropriate settings for operation is critical.

Impact to the system is also not only reserved to intermittent resources and energy storage. Other forms of generation such as fuel cells, microturbines, synchronous generation, etc., present unique considerations to the capacity planning process.

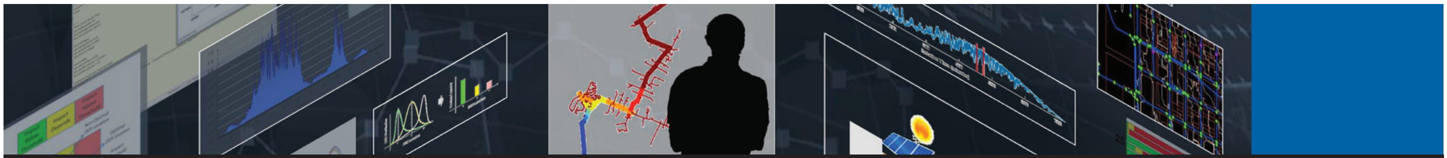
An effective method for determining distribution system hosting capacity for DER must take into account all of the factors listed above: location, feeder design, and DER technology. However the requirement doesn't stop there. Overarching components for effective analysis across an entire distribution system requires additional considerations.

Distribution-Wide Applications

In order for any method of analysis to find distribution-wide application, additional criteria must be met. The method must provide enough granularity such that it can distinguish the important factors that most affect hosting capacity: location, feeder design and operation, and DER technology. Requirements do not stop there, however. The method must also be scalable in order to analyze entire distribution systems but also repeatable to consider individual feeder modifications. Transparent and proven methods should also be used in order to gain confidence. Lastly, the method must also be available such that readily accessible data and distribution planning tools can be utilized.

Granular	• Capture unique feeder-specific responses
Repeatable	• As distribution feeders change
Scalable	• System-wide assessment
Transparent	• Clear and open methods for analysis
Proven	• Validated techniques
Available	• Utilize readily available utility data and tools

Figure 4 – Fundamental Components for Distribution-Wide Applications



EPRI has specifically designed a new method that is rooted in all of the components listed above. This new streamlined method for analyzing feeders is intended to provide distribution planners with the necessary capability to effectively and efficiently analyze DER impacts across the entire distribution system.

EPRI's Streamlined Hosting Capacity Method

Developing a New Approach

Throughout 2012-2014, EPRI performed detailed analyses of distribution feeders to determine the impact and hosting capacity for PV. Based on the correlation of the distribution impacts from this detailed analysis [4,5,6], trends in the impact were observed in three areas:

1. The magnitude based on aggregate DER penetration
2. The dependency on feeder characteristics
3. The dependency on the location of DER

Trends from these results formed the basis for a streamlined method of determining, on a feeder-by-feeder basis, hosting capacity across a distribution system. EPRI's Streamlined Method determines distribution impacts more quickly without compromising accuracy. Utilizing the original detailed approach, the engineering time associated with analyzing a single feeder was on the order of weeks. However in the streamlined method, a single feeder can be analyzed in a matter of minutes through the newer methods and automated nature of the analysis. The streamlined hosting capacity method does not replace the detailed analysis however, but does provide an analysis method between interconnection screens and detailed analysis thus allowing utilities to efficiently evaluate impacts and determine whether a more detailed study is necessary.

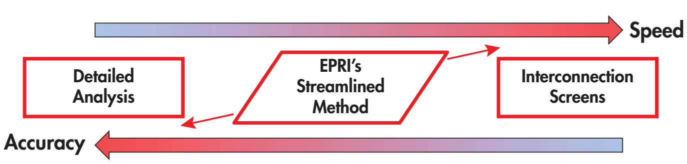


Figure 5 – Balancing Speed and Accuracy Between Different Approaches

Considering DER Impacts and Technologies

The streamlined hosting capacity method considers a wide range of impacts throughout each feeder based on what is commonly considered as part of a typical DER interconnection study. The four main categories are thermal, voltage/power quality, protection, and reliability/safety. Within each, there are a range of different outputs that result from the analysis of each impact shown in Table 1. Utilizing these outputs, the distribution planner can make a decision not only about interconnection impact, but also about how new systems might impact operation of the feeder over time.

Table 1 – Distribution Impacts Evaluated in Streamlined Hosting Capacity Method

Thermal	Power Quality/ Voltage	Protection	Reliability/ Safety
Substation Transformer	Sudden (fast) voltage change	Relay reduction of reach	Unintentional Islanding
Primary Conductor	Steady-state voltage	Sympathetic tripping	Operational flexibility
Service Transformer	Voltage regulator impact	Element fault current	
Secondary conductor	Load tap changer impact	Reverse power flow	

The method itself is DER technology neutral. While the primary focus for the original method [7] was solar PV, the new method has since been enhanced to consider other distributed technologies as well. To date, the streamlined hosting capacity method can be used to analyze the following technologies:

- Solar
- Wind
- Energy storage (unconstrained)
- Fuel cells
- Microturbines
- Synchronous machine (gas turbine, diesel generator)

The specific technology determines how the analysis is setup to properly quantify the unique impacts of the particular resource.

[4] Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV. EPRI, Palo Alto, CA: 2012. 1026640.
[5] Distributed Photovoltaic Feeder Analysis: Preliminary Findings from Hosting Capacity Analysis of 18 Distribution Feeders. EPRI, Palo Alto, CA: 2013. 3002001245.
[6] Alternatives to the 15% Rule: Modeling and Hosting Capacity Analysis of 16 Feeders. EPRI, Palo Alto, CA: 2015. 3002005812.
[7] A New Method for Characterizing Distribution System Hosting Capacity for DER: A Streamlined Approach for PV. EPRI, Palo Alto, CA: 2014. 3002003278.

The Core Analytical Method

In developing the Streamlined Hosting Capacity Method, it was critical that it remain rooted in the feeder model which allows observation of how feeder characteristics interact with one another. The feeder model is analyzed with a series of loadflow and fault studies. The loadflow study provides voltages, element loading, load allocation, and connectivity of the model, while the fault study provides impedance/resistance/reactance data.

The DER assessments are then performed by applying various DER "scenarios." These scenarios consider centralized (single-site) and distributed (multiple-site) DER locations. Thousands of scenarios are examined on all potential locations, or "nodes", on the distribution feeder. A simplistic illustration of a small subset of scenarios is shown in Figure 6.

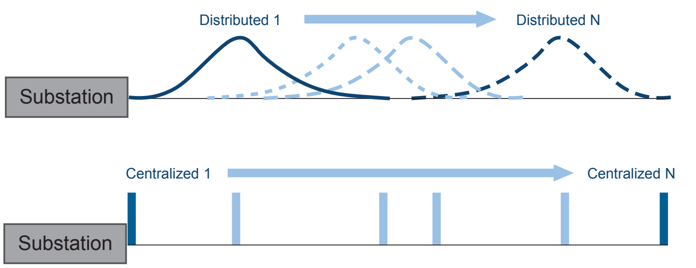


Figure 6 – Subset of DER Scenarios Analyzed in the Streamlined Analysis

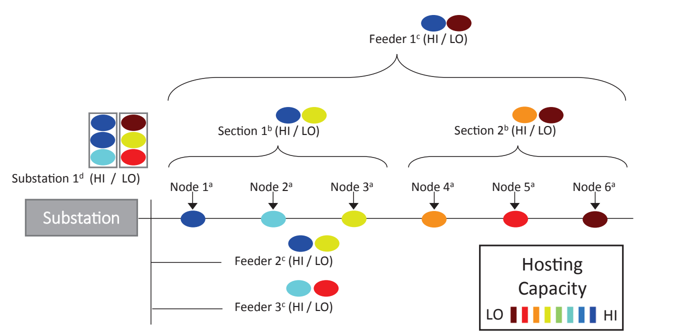
These scenarios make up the basis of the DER impact analysis. Each scenario results in a node-specific hosting capacity for DER at a specific location. The node is a point on the feeder between two line sections. Depending on the model, this may resemble locations in the field where the feeder branches, is sectionalized, or locations of power poles. For Centralized DER, a scenario's hosting capacity is based on DER at that location and does not consider DER at any other location on the feeder. For Distributed DER, a scenario's hosting capacity is depicted at the node where the DER is "centered" on the feeder and only considers DER at other locations based on the applied DER distribution. For both Centralized and Distributed DER, there are as many scenarios simulated as there are nodes on the feeder. Each scenario results in a hosting capacity value and therefore there are two hosting capacities at each node – one based on Distributed DER and another based on Centralized DER. The number of hosting capacity values then scales linearly with the number of distribution impacts considered.

A simple feeder example in Figure 7 illustrates hosting capacity at the node, section, feeder, and substation. In this example, one distribution impact is considered for centralized DER. The six nodes are each independently examined for the amount of DER that can be accommodated at that location. The colors indicate the resulting hosting capacity. The section hosting capacity is then the range in node hosting capacity on that section. Again, the section's HI/LO range is based on DER only at a single node along that section. Any DER on other sections will change the resulting hosting capacity. Similarly, the feeder hosting capacity is the range in node hosting capacity on the entire feeder. It is important to note that the feeder and section hosting capacity IS NOT the summation of individual node hosting capacities.

Each feeder can then be analyzed independently to determine their feeder hosting capacities. Aggregating further to the substation, one could determine the substations overall ability to accommodate DER. At the substation, the hosting capacity is the summation of individual feeder hosting capacities.

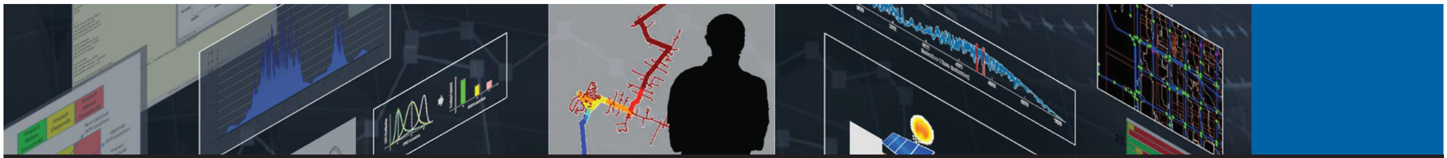
Considering the Time-Varying Impacts of DER

When evaluating actual DER impacts there are two aspects that one must consider, both time and space (location). The OpenDSS was originally developed by EPRI engineers to take both of these aspects into account. Time is a one-dimensional characteristics that, when considered properly, can be bounded by choosing the appropriate loadflow studies. Space, however, is multi-dimensional and therefore cannot be effectively bounded or approximated. As a result, in order to better quantify impacts the core method calculates the primary driver, location, and bounds time.



[a] Node Hosting Capacity is dependent on DER at other nodes. That shown above is based on DER only at the specified Node.
[b] Section Hosting Capacity is the HI/LO range in Node Hosting Capacity on that section.
[c] Feeder Hosting Capacity is the HI/LO range in Node Hosting Capacity on the feeder.
[d] Substation Hosting Capacity is the HI/LO range representing the summation of HI and LO Feeder Hosting Capacities.

Figure 7 – Example of Node, Feeder, Section, and Substation Hosting Capacity for Centralized DER and One Distribution Impact



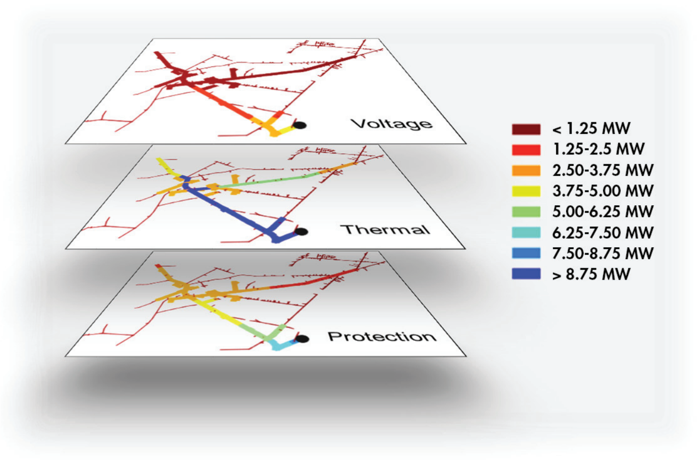


Figure 8 – Node Hosting Capacity for Three Distribution Impacts

One of the most effective methods to convey results is through visualization. Maps illustrating hosting capacity can easily be created through feeder models. Figure 8 shows a detailed hosting capacity solution for centralized DER and three distribution impacts. The hosting capacity is shown at the node, thus the color at the node depicts the amount of DER that could be accommodated at that location and nowhere else on the feeder. Each distribution impact can have a significantly different hosting capacity.

The node hosting capacity is ultimately the lowest based on all criteria considered. Figure 9 shows an example where the node hosting capacity reflects all issues chosen in the analysis for Centralized DER. The feeder hosting capacity then depicts the lowest hosting capacity from the node-based results. The entire feeder is shaded the same color to portray that DER penetration above that level may be problematic at some location on the feeder. There are many locations shown in the node-based results that can accommodate higher levels of DER, but any penetration less should not be problematic.

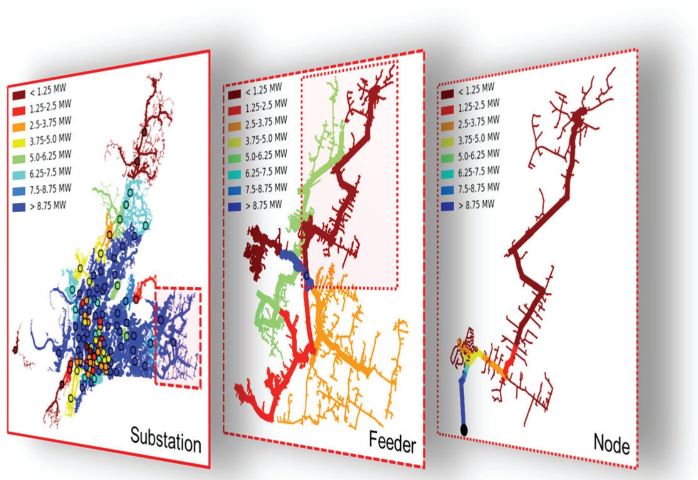


Figure 9 – Node, Feeder, and Substation Hosting Capacity

Feeders served out of the same substation transformer can have many different hosting capacities as shown in the feeder hosting capacity results. Out of seven feeders served from the substation transformer, one falls into the highest hosting capacity range while two fall into the lowest. The substation hosting capacity is the summation of all the individual feeder hosting capacities. All feeders served from the substation transformer are shaded the same color to represent the substations ability to accommodate DER. Again, the value shown in the example depicts the worst-case scenario that occurs on all feeders served. Alternatively, the best-case scenario can be portrayed for feeder and substation hosting capacity.

Applications

The Streamlined Hosting Capacity Method enables distribution planners to systematically analyze impacts of DER across an entire distribution system. Table 2 summarizes some of the potential applications for the results produced from such an analysis.

Table 2 – Potential Applications of the Streamlined Method

System-Wide Distribution Planning	• Determine DER impacts and hosting capacity on a feeder-by-feeder basis across the entire distribution system • Calculate capacity for accommodating new loads • Evaluate impacts on grid reconfiguration (operational flexibility) • Evaluate impacts and solutions realized through new technologies such as smart inverters
DER Hosting Capacity	• Improve screening techniques that effectively account for the proposed DER and associated grid capacity at that location • Identify locations that can minimize the upgrades necessary to accommodate DER • Provide better visibility to the specific issues that arise, where, and how often they might occur throughout the distribution system • Improve visibility into feeder- and substation-level capacity for accommodating DER • Inform transmission studies
Economics	• Provide technical basis for cost benefit assessments – Integrated Grid • Provide starting point for analysis of Energy, Asset Deferral, Mitigation

Requirements for Successful Implementation

The data requirements behind the streamlined method are typically found in models distribution planners use today. However, not all utilities have models of their entire distribution system and that can pose a challenge when needing to analyze a service territory.

Individual Feeder Modeling

The vast majority of data needed to perform the streamlined analysis are found within typical distribution feeder models. Valid electrical feeder models include feeder medium voltage lines and regulation equipment, customer loads modeled as they are in the field (location and phase), and substation equivalent impedance. Additional data that may or may not be readily available include non-peak solutions for the feeders as well as effective models of regulation equipment (settings, etc).

Distribution-Wide Modeling

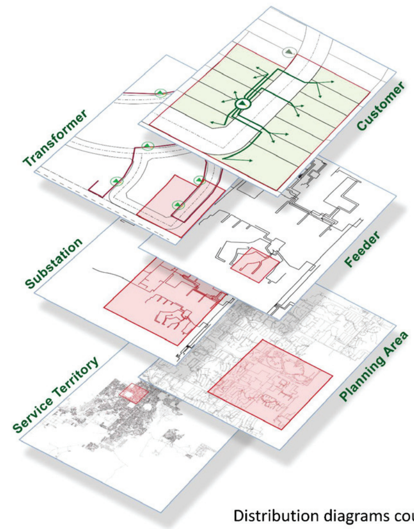
In order to perform this type of analysis across an entire distribution system, a large amount of data is required. The main challenge in successfully executing this analysis is if the entire system is not modeled or if the existing models do not accurately represent the current state of the system.

The Distribution System is Vast

An entire distribution service territory often consists of multiple large planning areas where substations and feeders have widely varying design and control parameters. Within each planning area, utilities may have 10’s to 100’s of substations that connect and deliver energy from the transmission to serve 100’s to 1000’s of different distribution feeders. Each of these feeders are outfitted with equipment for providing both voltage control and system protection with custom settings to enable the utility to serve all customers in an efficient and reliable manner.

Within each feeder there are 10’s to 100’s of service transformers that deliver power from the medium voltage down to a more usable, low-voltage service level. These transformers distribute this service through multiple secondary systems that connect each service transformer to individual residences, commercial buildings, and industrial complexes.

Therefore, customers located at the very “edge” of the grid – the typical distribution utility can have from 100,000s to 1,000,000s – are served by a vast and diverse number of feeders, substations, planning areas, and ultimately an entire distribution service territory.



Typical Distribution Utility	Number
Service Territory	1
Planning area	1’s - 10’s
Substations	10’s - 100’s
Feeders	100’s - 1000’s
Service Transformers	1000s - 1,000,000’s
Customers	100,000’s - 1,000,000’s

Distribution diagrams courtesy of Salt River Project

Figure 10 – Characteristics of a Typical Distribution Service Territory

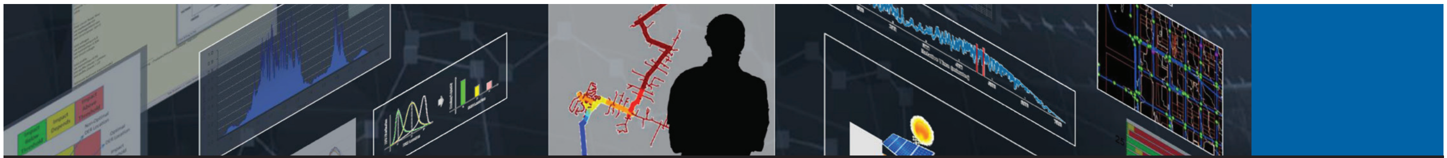
Challenges with Distribution-Wide Modeling

Utilities may or may not have models of the entire distribution planning area. In some cases, models aren’t needed for traditional planning purposes with one-way power flow. In such cases, it is not uncommon for utilities to rely on other means for planning that utilize rules-of-thumb combined with other data repositories such as GIS, asset documentation, and customer information systems.

In some cases only a limited number of distribution models are available. This typically occurs as an artifact from model development on an as-needed basis. Often times this has been initiated because of the need to evaluate a proposed DER interconnection. This can be a time-consuming exercise. Utilities are now in the process of documenting the system in a more detailed fashion in light of these needs.

As the grid is modernized, available and valid data has become more prevalent but it still remains a difficult and time consuming process

Historically, utilities have not found it necessary to model all of their distribution feeders to reliably and cost-efficiently serve all customers. As the need for better understanding of grid-edge impacts from DER arises, utilities are increasingly recognizing the need for such models and are working to improve the development and maintenance of models throughout the entire distribution system. Distribution models are a necessity when the desire is to analyze an entire distribution system.



to incorporate into planning models. One aspect of this difficulty in modeling is the overabundance of data and knowing what is pertinent to the feeder model.

A Moving Target

When distribution-wide models are available, maintaining databases of current field conditions can be quite challenging since the distribution system is constantly changing.

Over time, distribution feeders change due to planned upgrades, maintenance, outage restoration, etc. Additionally, new DER is being added on an ongoing basis. Maintaining system models is an ongoing process. Capturing the existing "status" of DER in addition to the traditional distribution assets will be key to creating valid distribution models. Utilities are in the process of documenting the system in a more detailed fashion and developing accurate system models in the process.

Committing Time and Resources

One of the previously mentioned goals of the streamlined method was to be efficient, thus very little time commitment is needed, if any, on the part of the utility engineer to perform the analysis. If valid distribution feeder models are available in current planning tools, a feeder hosting capacity analysis requires less than five minutes of computer time. However, as noted previously, as the distribution system changes over time, so should the underlying models. Therefore, maintenance of the distribution planning models to ensure they are up-to-date is an important aspect that can require additional time.

Implementation in Distribution Planning Tools

Rather than developing a new software tool, EPRI developed the methodology with the fundamental component to be available in existing distribution planning tools. Using tools distribution planners are familiar with today, the method leverages the existing data set to provide a much needed new functionality. Distribution planners are enabled to use this tool on an as-needed or regular basis to analyze individual feeders or the entire distribution system.

There are three main parts to implementing this method into commercial tools:

1. Standard interface to utility tools: The method is rooted in the feeder model and takes into consideration the full range in feeder design and operation. By systematically examining each model's power flow solutions and short-circuit responses, feeders can be properly characterized.
2. Core Methodology: The feeder design and operation data attained in Part 1 is analyzed and processed through a wide range of scenarios that incorporate what matters most when planning for DER. This analysis provides the node-specific impact assessment. This node-specific assessment can then be aggregated up to the feeder, substation, and system level.
3. Reporting: The impact results from Part 2 are then interpreted and conveyed through visual outputs.

To date, through the support of various utilities, the streamlined hosting capacity method has been successfully applied to work with:

- CYME (using self-contained study files as well as Access databases),
- Synergi (using Access databases), and
- Milsoft (using models exported into OpenDSS).

Additionally, EPRI is currently working on implementation in PowerFactory.

CYME, Synergi, and OpenDSS use the Python COM interface to apply the method within current versions of the software. Working alongside utility partners, the implementation has been customized for use based on specific database structures and data sets. Utility partners in this supplemental project to date include: Tennessee Valley Authority, Southern Company, Salt River Project, Xcel Energy, Central Hudson, and Eskom.

In total, upwards of 3,000 feeders have been analyzed with a goal of providing the tool such that the remainder of each utilities distribution system can be analyzed. Once implementation is complete, the method and tool compatible with the distribution planning software will be made available through EPRI program membership. The timeline of execution is shown in Figure 11.

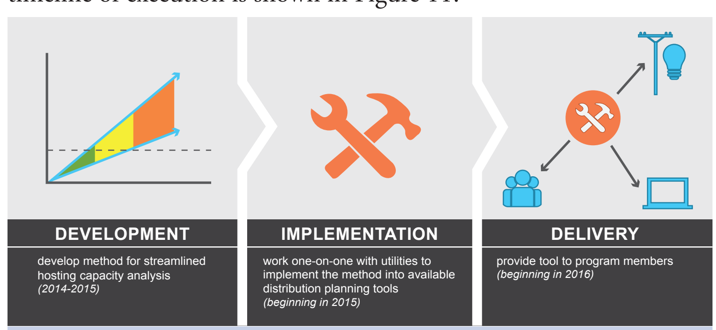
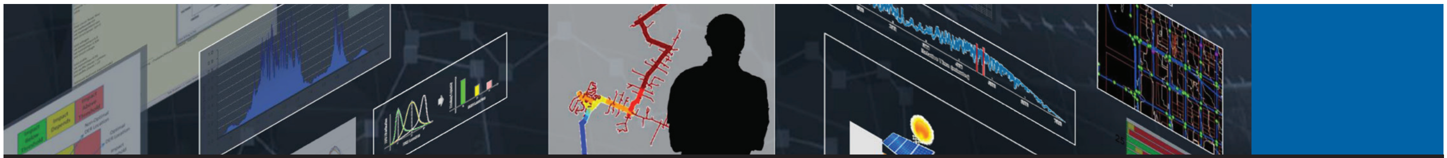


Figure 11 – Plan for Development, Implementation, and Delivery



Ongoing Work

With this process in mind, EPRI plans to continue expanding the core methodology over the next few years to add additional functionality/capability. The main areas of growth identified thus far include:

- Incorporation of existing DER in hosting capacity analysis
- Expansion of energy storage analysis to consider constrained and utility controlled modes
- Ability to consider the use of solutions to effectively increase hosting capacity, such as
  - smart inverters
  - storage
  - feeder operation
  - infrastructure upgrades
- Ability to consider a combined portfolio of DER technologies
- Improved evaluation of the localized secondary impact from DER
- Incorporation of expected customer DER adoption
- Implementation of similar techniques to determine the true value of DER

Conclusions

Effective and efficient means for evaluating the impact of DER is a necessary aspect of distribution engineering today. Instead of requiring specialized analysis and skillsets, new methods are needed that utilize existing distribution planning tools, can be performed by existing distribution planning personnel, and use readily available data that most distribution planners have on hand.

EPRI has developed such a methodology and is working alongside utilities and vendors alike to implement this method within existing distribution planning tools. This is a first, but crucial step towards effectively integrating DER into the distribution system by considering it in the planning process.

The utility will continue to plan and operate the grid as they always have: efficiently, safely, and reliably. New technologies connecting to the distribution system will continue to evolve. In the end, the normal planning functions and tools used by utilities today will be needed; but they need to evolve, in order to reflect this new landscape of the "distribution system of things."

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Power System Studies

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ATTACHMENT D

ORA Powerpoint Presentation from November 10, 2015 Workshop.

ORA

OFFICE OF RATEPAYER ADVOCATES

Evaluation of Utility Integration Capacity Analyses (ICAs)

ICA Workshop– November 10, 2015

Tom Roberts, Senior Engineer

ORA's Objectives Regarding DRPs

- CPUC and state policies correctly implemented
- Avoid artificial barriers to distributed energy resource (DER) interconnection –(ICA specific)
- Avoid unreasonable ratepayer expenditures for distribution infrastructure upgrades
- Realize maximum ratepayer savings for distributed resource plan (DRP) investments

ORA Discovery

- First phase of data requests (DR) to PG&E only
- Six DRs related to DRPs, existing assets/facilities, distribution planning, and 43 questions focused on ICA:
  - PG&E's responses generally very helpful in building a better understanding of its ICA
  - PG&E labeled three responses and one attachment labeled Confidential
  - Remaining questions to be addressed through meeting
- ORA can provide copies of questions to parties, but responses should be obtained through PG&E

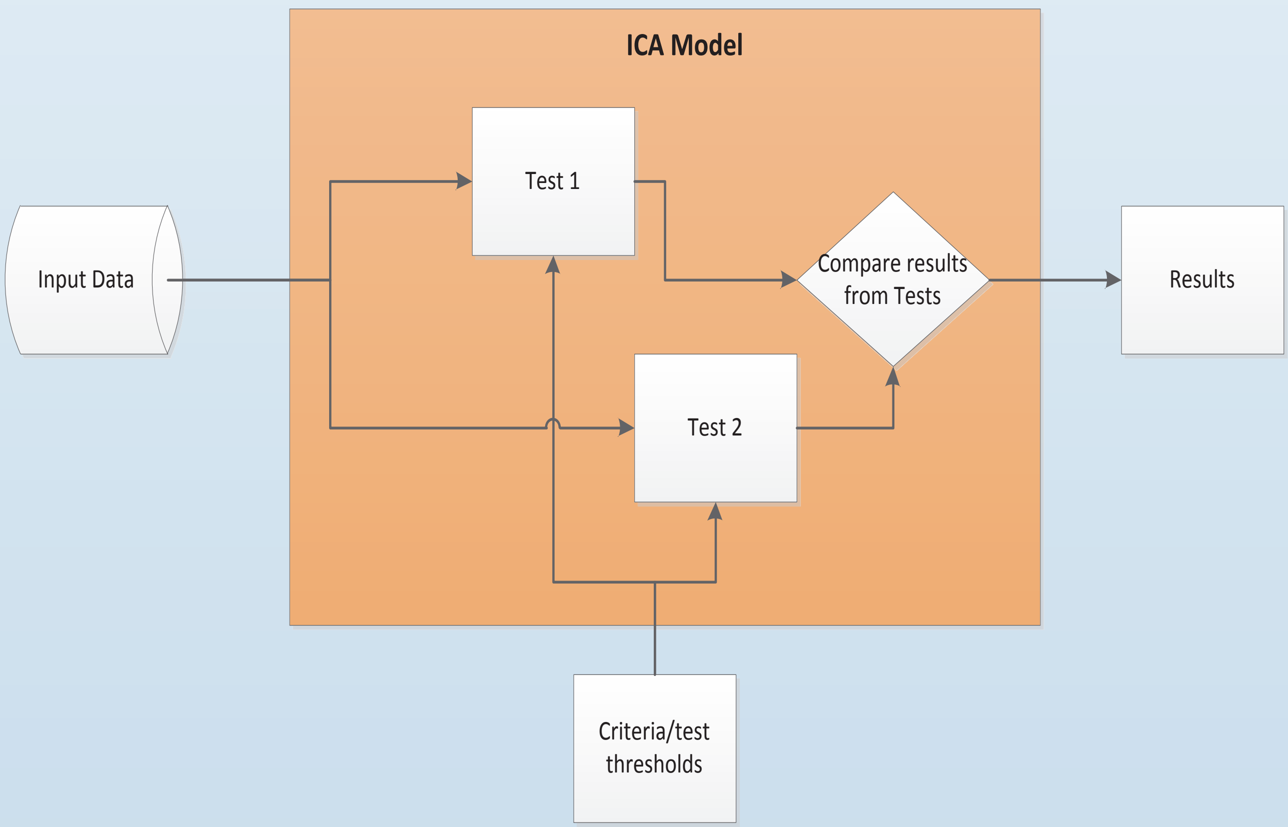
ORA Results to Date

- Responses to DR questions synthesized into DRAFT flow charts of PG&E ICA process
- List of ICA effectiveness criteria
- Keys to accurate results
- Catalog of open questions
  - Some we hope to discuss today
  - Most we plan to discuss with PG&E directly

ORA Flowcharts of PG&E ICA

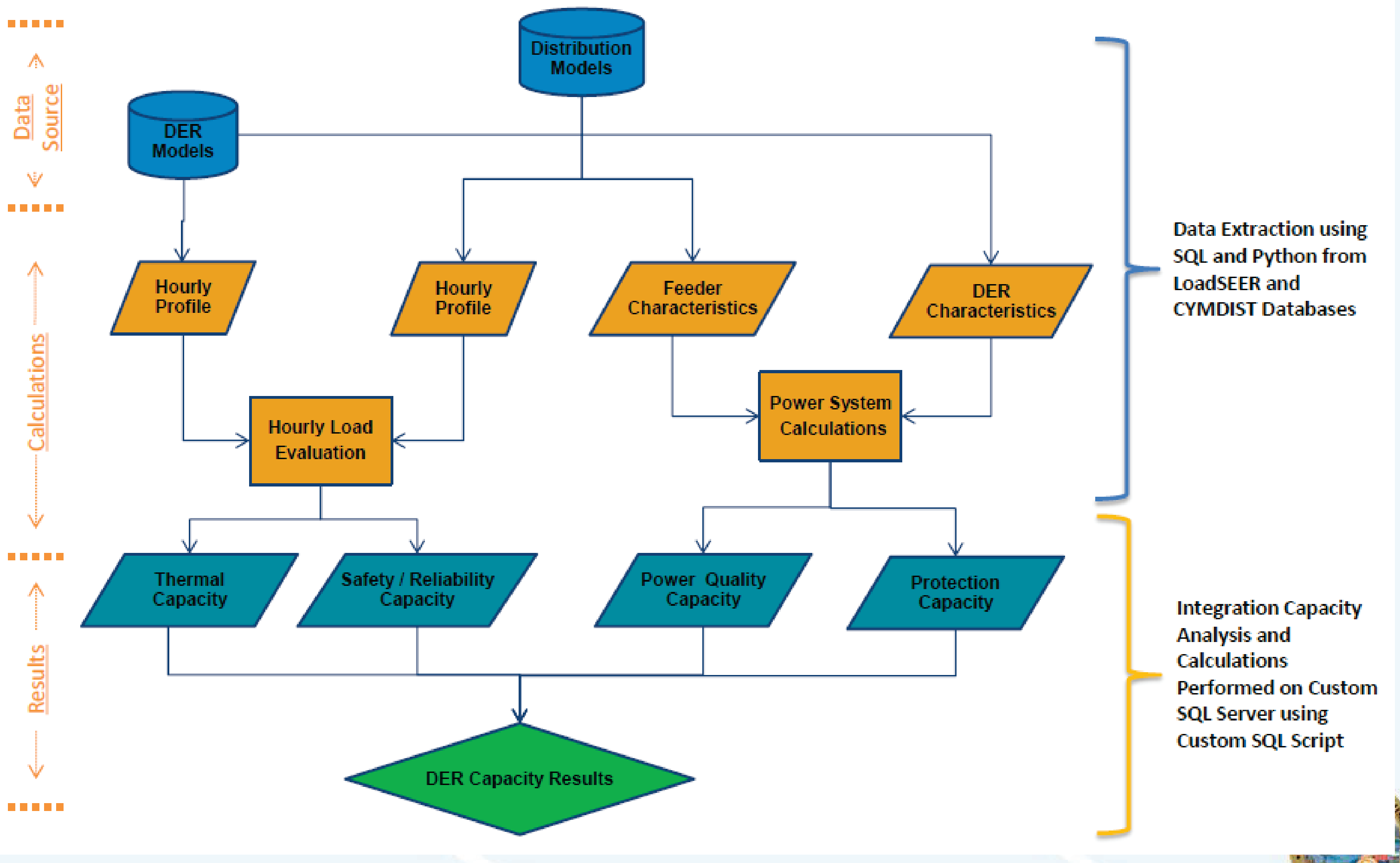
- Deemed necessary based on ORA experience with PG&E gas pipelines, post-San Bruno
- Work in progress, **NOT** vetted by PG&E
- These drafts intended as a strawman to:
  - Help parties and CPUC staff understand ICA data sources, process, tests, and all tools
  - Provide an outline for PG&E to correct and flesh out

General ICA Methodology - Simplified



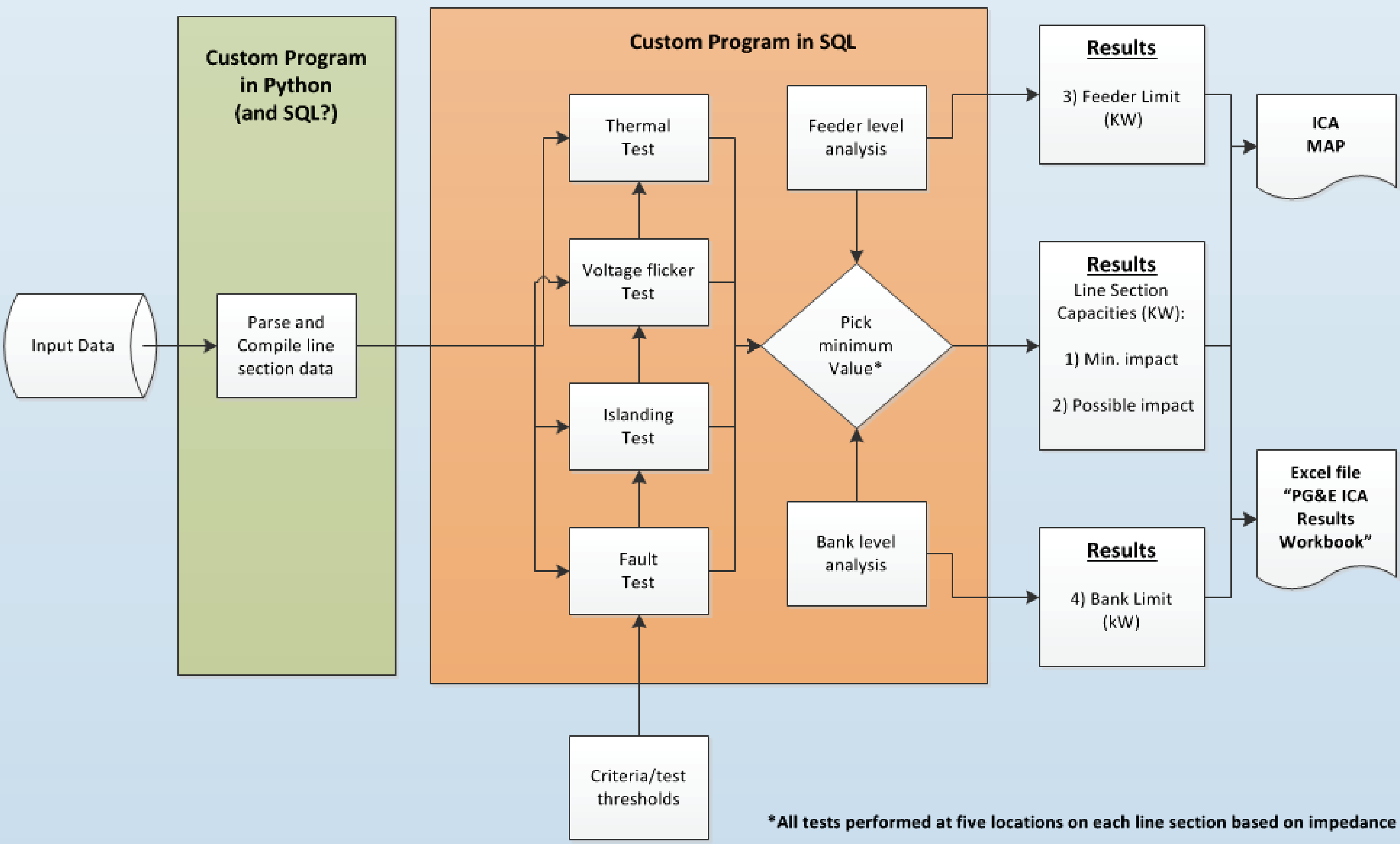
Source: ORA DRAFT

PG&E ICA Flow Chart



Source: Slide 23 of attachment to PG&E response to DR-ORA-004-Q8

PG&E ICA Methodology -Simplified



*All tests performed at five locations on each line section based on impedance

Source: ORA DRAFT

PG&E ICA Tests and Criteria

- Thermal test
  - kW limit = $$Min\left(\frac{Capability - Gen_{FDR}[mn][hr] + Load_{FDR}[mn][hr]}{DER_{pu}[mh][hr]}\right)$$
- Voltage test
  - kW limit = $$\frac{(3\% * {V_{LL}}^2)}{(R * PF_{DER} + X * \sin(\cos^{-1}(PF_{DER})))} * PF_{DER}$$
- Islanding test
  - kW limit = $$Min\left(Max\left(\left[\frac{Load[mn][hr] * 0.5}{DERpu[mh][hr]}\right], \left[\frac{DG_{existing}[mn][hr] \div RatioThreshold}{DERpu[mh][hr]}\right]\right)\right)$$
- Fault test
  - kW limit = $$\frac{10\% * I_{Fault\ Duty} * kV_{LL} * \sqrt{3}}{\left(\frac{Fault\ Current_{DER}}{Rated\ Current_{DER}}\right)} * PF_{DER}$$

PG&E ICA Methodology – Part 1

Custom Program in SQL

Input Variables												Criteria	Test
Equipment Termal Limits	Load - level and profile	New DER - level and profile	Existing DER - level and profile	"Ratio Threshold"	VLL	"R"	DER Power Factor	"X"	Fault duty current	DER fault current	DER rated current		
X	X	X										100%	Thermal Limit
					X	X	X	X				3%	Flicker Limit
X	X		X	X								50%	Islanding Limit
					X		X		X	X	X	10%	Protection Limit

Feeder level analysis

Pick minimum Value*

Bank level analysis

Results
3) Feeder Limit (KW)

Results
Line Section Capacities (KW):
1) Min. impact
2) Possible impact

Results
4) Bank Limit (kW)

Ref A

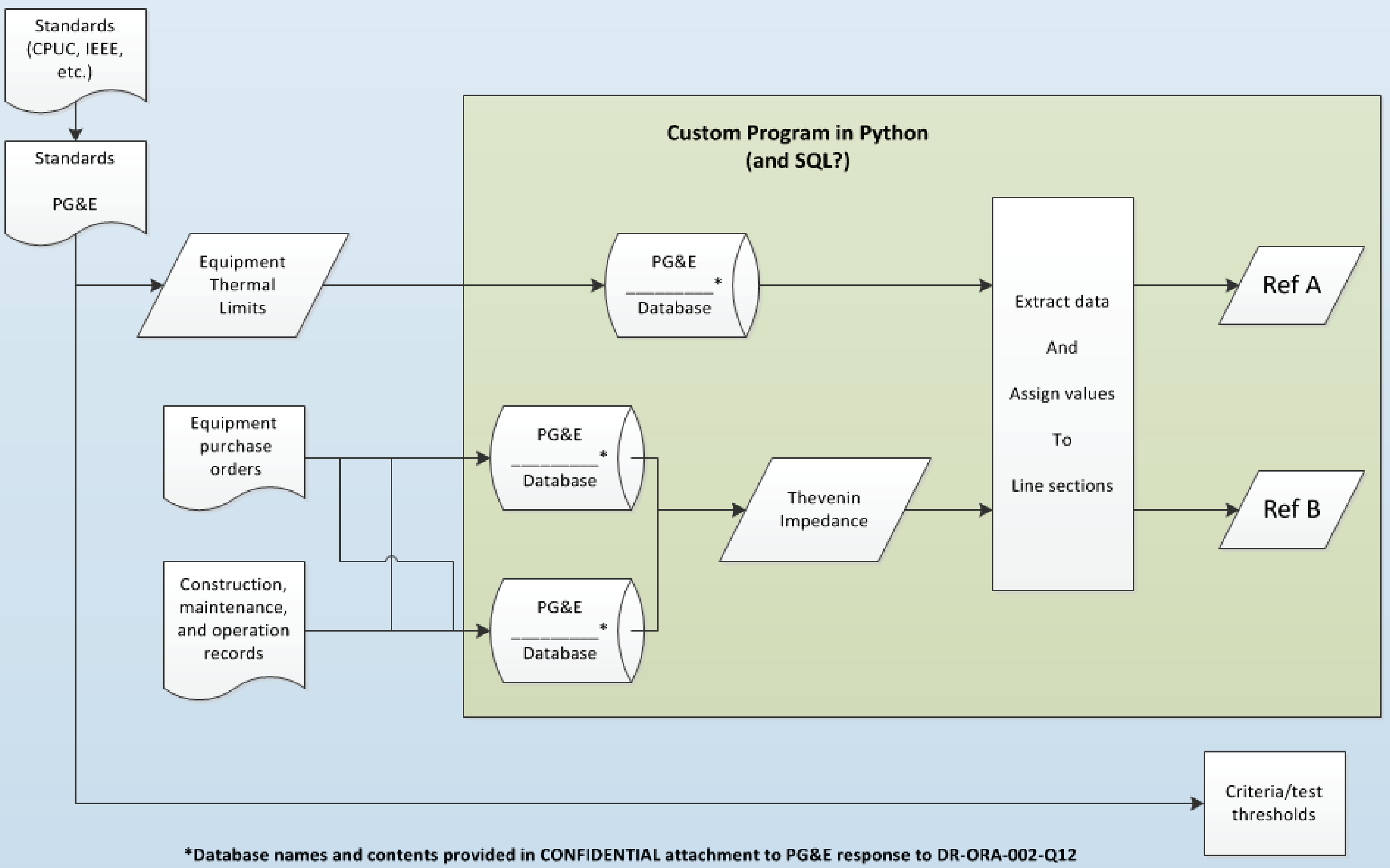
Ref B

Criteria/test thresholds

***All tests performed at five locations on each line section based on impedance**

Source: ORA DRAFT

PG&E ICA Methodology – Part 2



*Database names and contents provided in CONFIDENTIAL attachment to PG&E response to DR-ORA-002-Q12

Source: ORA DRAFT

ICA Effectiveness Criteria, Part 1of 2

1. Accurate and meaningful results – details on Slide 14
2. Transparent methodology
3. Uniform process that is consistently applied
4. Complete coverage of service territory
5. Useful formats for results
6. Consistent with industry, state, and federal standards

ICA Effectiveness Criteria, Part 2 of 2

7. Accommodates portfolios of DER on one feeder
8. Reasonable resolution
   – Spatial
   – Temporal
9. Easy to update based on improved and approved changes in methodology
10. Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.)
11. Consistent methodologies across large IOUs
12. Methodology accommodates variations in local distribution system, such that case by case or distribution planning area (DPA) specific modifications are <u>not</u> needed

Keys to Accurate and Meaningful Results

A. Meaningful scenarios
B. Reasonable technology assumptions
C. Accurate inputs (i.e. load and DER profiles)
D. Reasonable tests (i.e. voltage flicker)
E. Reasonable test criteria (i.e. 3% flicker allowed)
F. Tests and analysis performed consistently using proven tools, or vetted methodology
G. Meaningful result metrics provided in useful formats

Preliminary Observations

- Limiting scope to 3-phase circuits leaves out a large portion of feeders (49% based on mileage, 63% based on customers)
- Automating tests via script/codes helps ensure consistency, but full vetting and QA/QC is required
- Granularity of analysis is currently limited by aggregate customer class load profiles
- Test/criteria (thermal vs. flicker) driving IC for each line segment is not currently available

Preliminary Conclusions

- Each IOU should provide full documentation of entire ICA methodology and QA/QC procedures to all parties, including flowcharts of entire methodology
- Parties and CPUC staff should be allowed time to review these additional details before a determination of ICA adequacy and consistency is made
- ORA looks forward to working with utilities to fully understand the ICAs, and working with CPUC staff and parties to help ensure the ICAs meet consensus effectiveness criteria

ATTACHMENT E

PG&E Presentation, Slide 27, 31 - 34

PG&E's Distribution Resource Plan

Details on Integration Capacity Analysis

January 2016

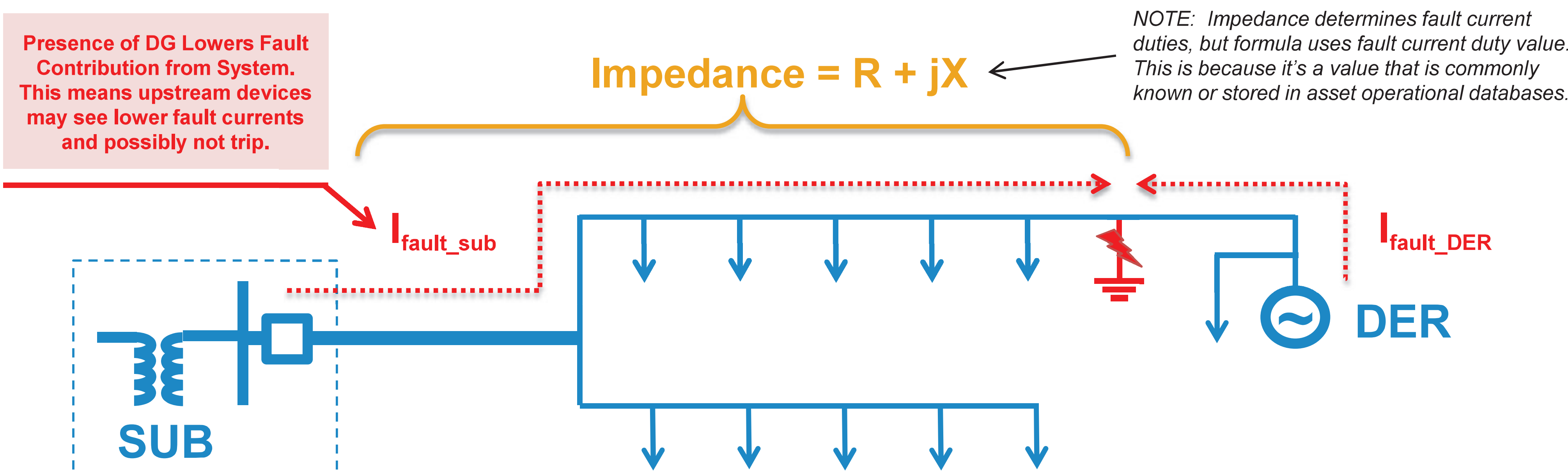
Lead Developer: Tom Russell, *Senior Engineer*, Distribution Resource Planning
Python Developer: Sarah Walinga, *Engineer*, Engineer Rotation Development Program
Python/Tool Support: Brian Agnew, *Engineering Supervisor*, Distribution Planning
Planning/Tool Support: Donovan Currey, *Expert Engineer*, Distribution Planning
IT Support: Jerome Ruffner, *Senior Programmer Analyst*, IT Grid Ops Applications
Mapping Support: Kassim Visram, *GIS Application Engineer*, Electric GIS Mapping

Protection Reduction of Reach Limit

The most common effect DG will have to a protection system is to lower the amount of fault current the system feeds from the transmission system. This concept is considered "Reduction of Reach" as the generators reduce the fault from the substation and reduce the ability of the utility relays to see faults on the system.

- The effect that added DG might have on protection schemes must be evaluated.
- The 10% evaluation has historically been used to flag possible protection issues as protection schemes are very complex dynamic systems.
- Future enhancements to this evaluation will look to dynamically tie this formula to locational trip settings for protection devices to get more accurate results to when DER will impact protection schemes

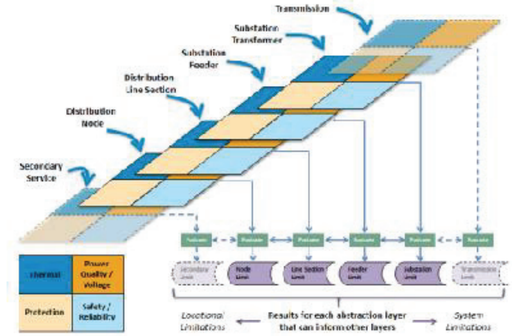
$$kW\ Gen\ Limit = \frac{10\% \ * I_{Fault\ Duty} * \ kV_{LL} \ * \ \sqrt{3}}{\left(\frac{Fault\ Current_{DER}}{Rated\ Current_{DER}}\right)} * PF_{DER}$$

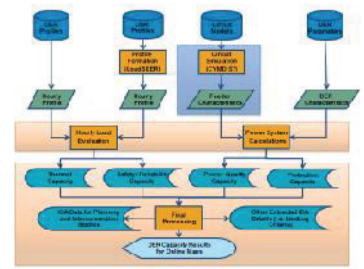


Appendix: Process Flowcharts

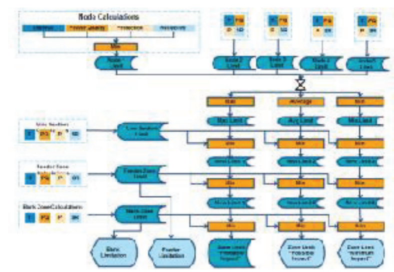
The following slides depict flowcharts that help explain the process flow from data sources to implement the general methodology

- **Abstraction Technique for ICA Processing Similar to EPRI**
  - Outlines general process of how ICA was implemented on a given layer of the system (i.e. nodes) from data sources to end results. This abstraction technique allows for explicit determination of limits across all the evaluated categories by breaking down to formulaic calculations. It also reduces the dependency for new coding needs as it allows for pulling of data from existing data sources and processes.

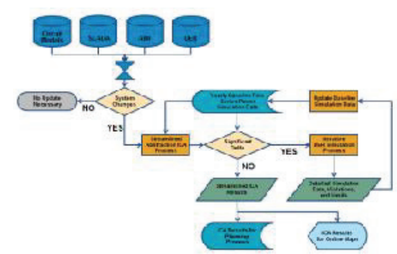




- **Abstraction Process to Integrate Values between System Layers**
  - Outlines general process implemented for organizing and integrating final results formulated across the various system layers (i.e. node, feeder, substation). The abstraction technique allows for easier integration of various system layers that might not be explicitly in the distribution simulation model

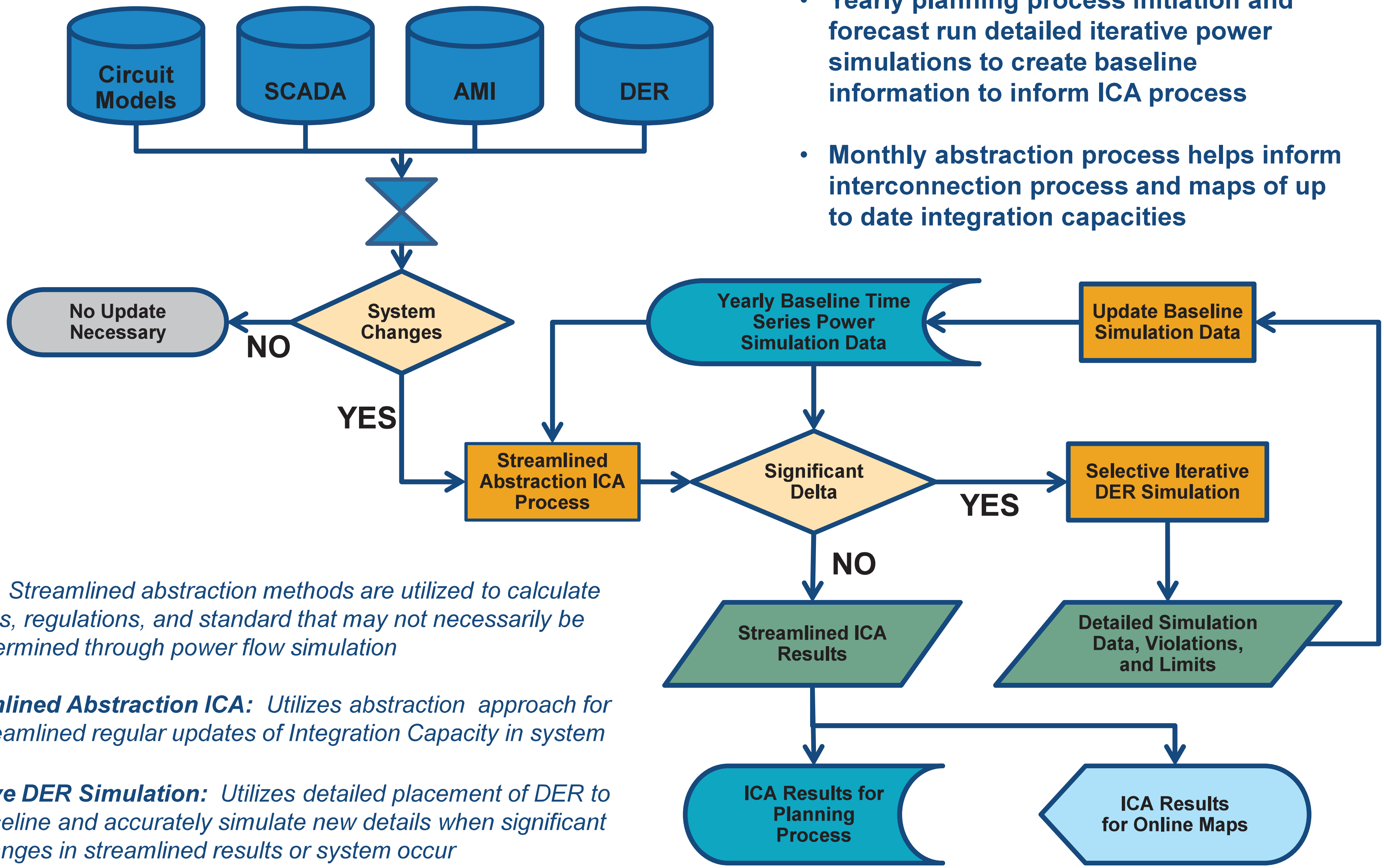


- **Improved Abstraction Process for Future Enhancements**
  - To explore in Demo/EPIC projects
  - This approach creates a convergence of iterative simulation of DER placement and abstracted formulaic calculations in an integrated improved process. This robust processing technique could allow for more detailed simulated values while achieving efficient regular processing for shorter time frame updates.



Improved Abstraction Process for Future Enhancements

- Yearly planning process initiation and forecast run detailed iterative power simulations to create baseline information to inform ICA process
- Monthly abstraction process helps inform interconnection process and maps of up to date integration capacities



NOTE: *Streamlined abstraction methods are utilized to calculate rules, regulations, and standard that may not necessarily be determined through power flow simulation*

Streamlined Abstraction ICA: *Utilizes abstraction approach for streamlined regular updates of Integration Capacity in system*

Iterative DER Simulation: *Utilizes detailed placement of DER to baseline and accurately simulate new details when significant changes in streamlined results or system occur*

ATTACHMENT F

SCE ICA Webinar, Feb. 19, 2016, Slide 3 - 4

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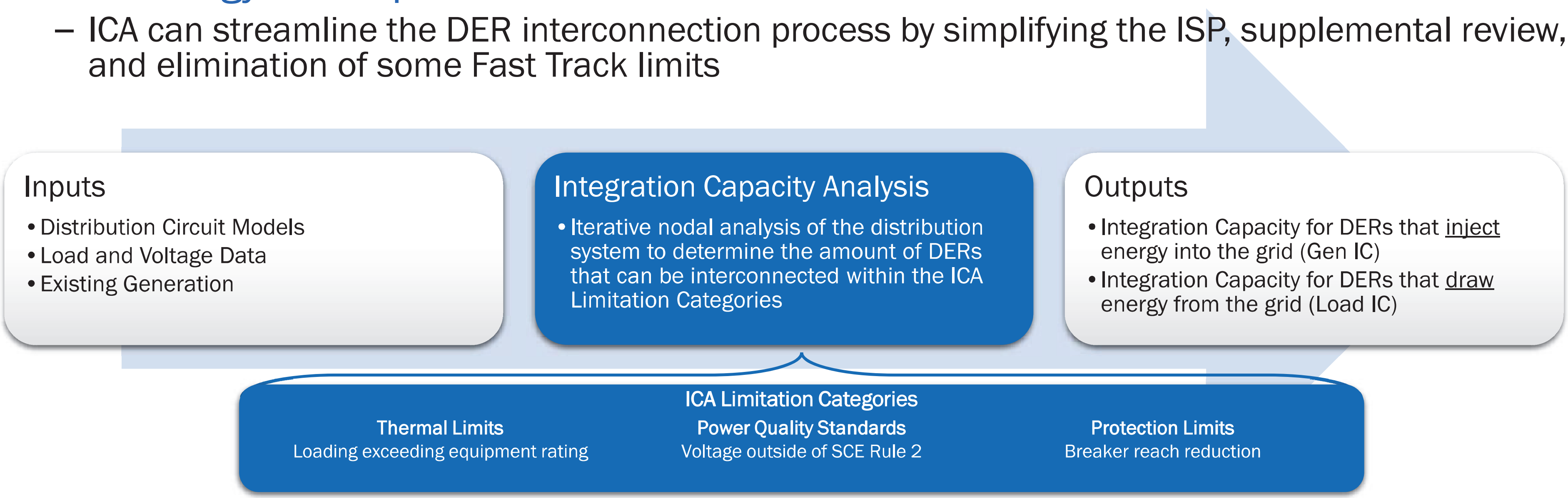
SCE ICA Webinar

February 19, 2016

Integration Capacity Analysis (ICA)

- The ICA quantifies the amount of DERs that can be interconnected on each node[1] across the distribution system within thermal, voltage, and protection system limits
  - ICA answers the question, “How much generation can I install on this line section without triggering distribution system upgrades?”
- SCE used the Interconnection Study Process as the foundation of its ICA Methodology development
  - ICA can streamline the DER interconnection process by simplifying the ISP, supplemental review, and elimination of some Fast Track limits



[1] Node is the transition point between electrical devices, as modeled by SCE mappers. Distribution circuits can have upwards of a thousand nodes

2015 DRP ICA Limitation Categories

Limitation Categories	Description of Limitation Category	Limitation Detail	Risks
Thermal Ratings	Hosting Capacity limited to the amount of DERs that may cause the loading on electrical devices to exceed thermal ratings or planned loading limits	Loading on distribution grid devices shall not exceed thermal ratings or planned loading limits	• Equipment Degradation • Equipment Failure • Outages • Public/worker safety
Protection System Limits	Hosting Capacity limited to the amount of DERs that may hinder protective devices' ability to detect and isolate faulted conditions	Per EPRI's Hosting Capacity studies, SCE included Breaker Reach limitations in its methodology.	Reduction in ability of protective devices to detect/clear faults on the system • Equipment damage/failure • Public/worker safety
Power Quality Standards	Hosting Capacity limited to the amount of DERs that may cause voltage violations on the primary voltage of the distribution circuits	DERs shall not cause violations of SCE Rule 2	• DERs may disconnect from system • Damage to customer equipment • Public/worker safety
Safety Standards	The above limitation categories support the safe and reliable operation of the SCE Distribution System		

- Other EPRI Categories: Voltage Deviation, Reverse Power Flow, Element Fault Current, Sympathetic Breaker Tripping

ATTACHMENT G

SDG&E Presentation, Slide 5

A Sempra Energy® utility

San Diego Gas & Electric

Distribution Resources Plan
ICA Deep Dive

John Baranowski
Electric Distribution Planning Manager

Criteria

- Steady State Voltage ranges
  - 116V – 126V Non-CVR circuits
  - 116V – 123V CVR circuits
- Voltage deviation/flicker
  - 3% change
- Thermal limits
  - Determined by manufacturer and SDG&E standards dept
  - 90*C rating for UG cables
  - nominal rating for OH conductors
  - Manufacturer rating for switches and other line equipment
- Protection limits
  - Fault interrupting capability determined by manufacturer

SDGE
A Sempra Energy utility